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NORTH CENTRAL POWER STUDY

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North Central Power Study
Report of phase I, study of mine-mouth thermal powerplants with extra-high-voltage transmission for delivery of power load centers.

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NORTH CENTRAL POWER STUDY

Report of Phase I

Volume 1

Study
of
Mine-Mouth Thermal Powerplants
with
Extra-High-Voltage Transmission
for
Delivery of Power to Load Centers

Prepared Under the Direction of
Coordinating Committee
North Central Power Study

October 1971

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North Central Power Study
Volume I

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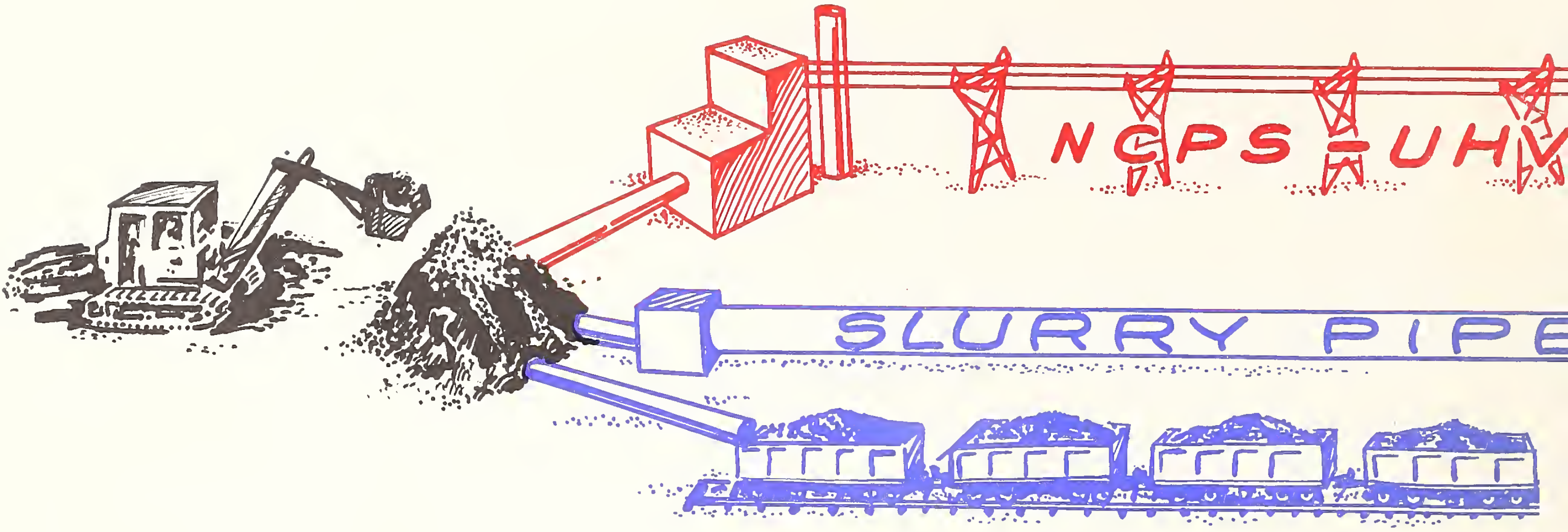
FOREWORD

The North Central Power Study was a coordinated undertaking of the power supply entities in the North Central and Rocky Mountain areas of the United States. By a concentrated effort the Study was completed and this report issued in about one year. The reporting of the Study is contained in two volumes. This volume, Volume I, is a summary of the work and results of the various committees and task forces organized for the Study. Volume II, an appendix, provides detailed reports in support of Volume I. The working relationships that were established in the course of this Study should serve as an expanded base for further coordinated planning in the area.



I. INTRODUCTION

The stated purpose of this Study was to promote the coordinated development of electric power supply in the North Central United States. The key resource in the Study is coal and through the use of mine-mouth generating plants at the coal sites and long distance UHV transmission the proposed plans could serve a significant portion of the Study area load growth for many years. The vast supplies of coal and the small load in the areas near the coalfields were considered likely to result in these areas becoming energy exporters. Several previous studies have made important contributions to the general concepts involved, but those studies had limited sponsorship, whereas the NCPS drew from the technical expertise and views of practically all bulk power suppliers in the 1,000,000 square mile area.

The total North Central Power Study area was separated into two areas for system design purposes: one east of the present East-West ties and the other west of the ties. The East-West ties are located in the Rocky Mountain area and connect the power systems of the eastern and western United States.

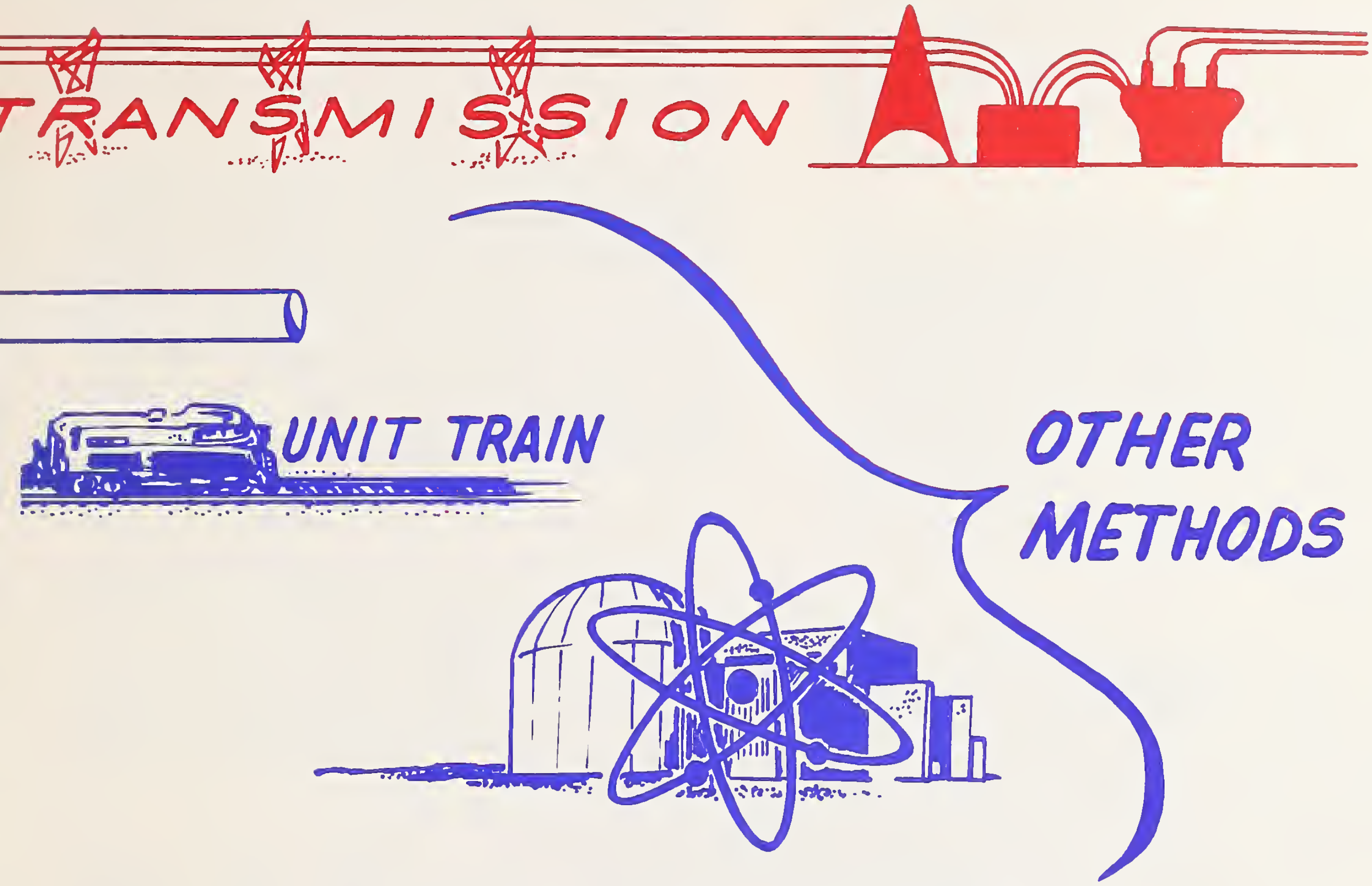
In presenting this report, the participants wish to make certain that those persons and agencies directly involved, and the public at large, understand that the participants fully recognize the very real concern for the environment. The participants fully intend such development of generation will be responsive to this concern, will be studied in detail with respect to the accumulative impact on the environment, and will incorporate whatever methods and facilities are necessary to minimize this impact.

I A HISTORY

On May 26, 1970, Assistant Secretary of the Interior James R. Smith launched the North Central Power Study when he met with executives of the major power suppliers of the North Central United States. He explained the need for a coordinated joint study to investigate the power needs and resources for the area through the year 2000. The basic idea was to investigate the feasibility of constructing large mine-mouth thermal plants located in the substantial coalfields just east of the Rocky Mountains and, by the use of extra-high-voltage transmission lines, deliver economic power to major load centers.

As a result of the May 26, 1970, meeting a Coordinating Committee was organized to outline procedures for and oversee the development of such a study. This Committee was composed of a management representative from each interested utility and ultimately included 19 investor-owned, six cooperative, two public power district, one Federal, and eight municipal representatives. It in turn designated a Steering Committee and a Study Manager to set guidelines, assign personnel, and directly oversee the implementation of the study.

At a meeting in Denver, Colorado, on September 2, 1970, the Coordinating Committee approved: (1) Study Scope and Guidelines, (2) Committee and Task Force Guidelines, (3) personnel appointments to committees and task forces, (4) a permanent Steering Committee, (5) a method of funding computer costs for the study, and (6) the goal of completing the study in approximately 1 year. On September 14, 1970, the Steering Committee met



with all the working committee and task force chairmen and initiated the actual detail work for the study named the NORTH CENTRAL POWER STUDY.

There were seven meetings of the Coordinating Committee, 14 meetings of the Steering Committee, and numerous meetings of the working committees and task forces during the course of the Study. Personnel involved were experts in their professional fields and carried out their duties expeditiously, while continuing the normal workload required of their positions.

This first phase of the Study was completed approximately as scheduled. With the time limitations imposed, it was not practical to investigate all the many alternatives concerned, but adequate information was obtained for the reconnaissance-type investigation required.

The Study was conducted by representatives of the participating systems with management and manpower equally shared between the Federal Government and the other participants. It has provided a comprehensive planning effort between public, private, and Federal power entities in the area.

I B CRITERIA

Criteria for the North Central Power Study were originally developed in June of 1970 and were revised or added to up until the final report was completed. The salient factor in all considerations of basic criteria was the limited time to complete such a wide-ranging study. Detailed criteria are presented in Volume II of this report.

The basic guidelines and criteria were approved by the Steering Committee; however, it must be realized that compromises were necessary and each individual member was not in full agreement with all the basic assumptions adopted. Below is a summary of the basic guidelines and criteria adopted with short explanations, where applicable, of the reasons for their inclusion:

1. GENERAL PLAN OF STUDY—The general plan for the Study was for the working committees and task forces to develop all the required information to determine the feasibility of installing large generating complexes in the coalfields of the Study area. Existing information from the many individual utility and pool studies was to be utilized to the fullest extent. Various alternatives were to be

studied and cost data developed. For example, plans composed of thermal generation of various capacities from 4,000 mw to 50,000 mw, integrated with hydropeaking at the largest level of thermal development with transmission to various delivery points, would be investigated.

2. PHASES—A three-step program was anticipated for the Study: Phase I would be the development of costs for a general overall plan as outlined in paragraph 1. above. Phase II would have each utility determine its level of interest in participating in various plans and redo Phase I, based upon the new distribution and magnitude of actual participation loads. Phase III would involve implementation of contractual arrangements and actual construction.

3. PARTICIPATION—Study participants were from a wide geographic area covering the Missouri River Basin and adjacent areas. Any major electric power organization constituted to purchase and sell power within this area could be represented on the Coordinating Committee; smaller entities could be represented on a group basis with the approval of the Coordinating Committee.

4. TIMING—The Study goal was to achieve publication of the final report approximately 1 year from initiation of work by the task forces.

5. AREA TO BE STUDIED—The Study area was limited to the Coordinating Committee load area and includes all or parts of the states of Utah, Colorado, Wyoming, Idaho, Montana, North Dakota, Missouri, South Dakota, Nebraska, Kansas, Iowa, and Minnesota and minor parts of Illinois, Oregon and Wisconsin. Inclusion or not of the complete power systems of boundary line participants would be made at the discretion of the concerned committees and the individual participant. Although the Pacific Northwest was not included in this first phase of the Study, interest had been expressed by certain entities, and this participation can be pursued in Phase II of the Study. Approximately one-third of the load growth in the area for the years 1978-2000 was assumed to be the maximum power served by the NCPS program.

6. YEARS TO BE STUDIED—The Study would encompass the period from 1978 to 2000. Initially, for data gathering and analysis purposes, the years of 1980, 1985, 1990, and 2000 were to be investigated.

7. COMPUTER STUDIES—Detailed computer studies were performed to test the adequacy and reliability of planned transmission system. Originally it was anticipated that classical stability and loss of load probability studies would be performed on a computer; however, due to lack of time, it was agreed that analytical methods would be used which would result in the accuracy required for Phase I investigations.

8. ALTERNATIVE POWER COST COMPARISONS—The Study was conducted on the basis of deriving the costs of delivering power and allowing individual entities to determine whether these costs compared favorably with their alternatives. Sufficient details of the economic derivations are included in the final report so that practical comparisons could be made.

9. STUDY COSTS—With the exception of the computer studies, Study costs included personnel expenses and travel costs which were borne by the individual entities. It was assumed that actual computer rental costs would not exceed $50,000, which would be equally proportioned among the participants on the Coordinating Committee. The cost of publishing and mailing the final report and progress reports was assumed by the Government.

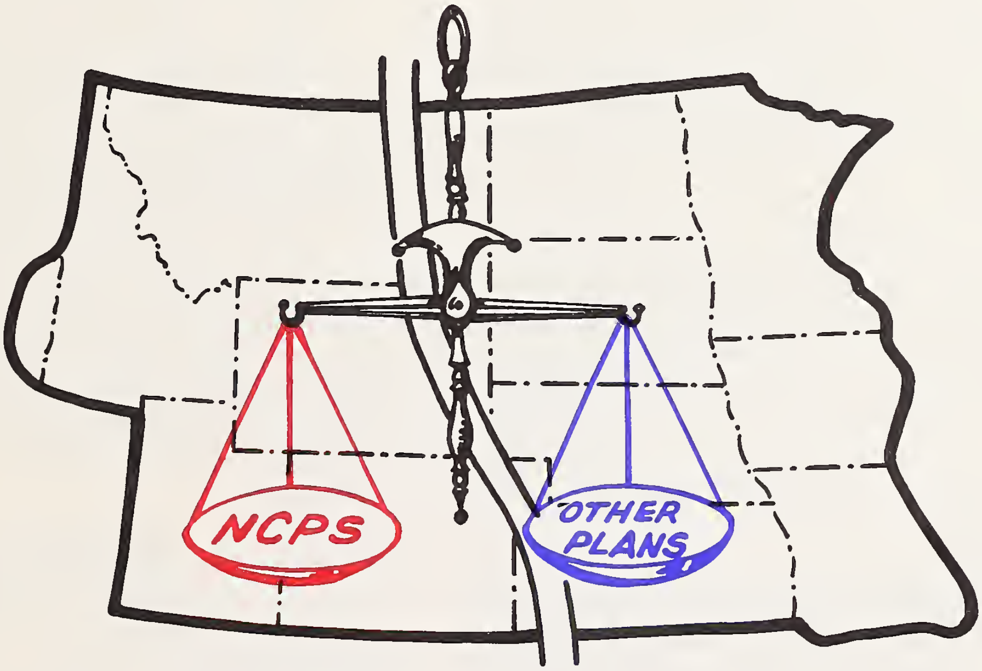
10. TECHNOLOGY—In order to obtain practical results it was decided to base the Study on existing technology. It was realized that by the time of actual implementation of detailed design or construction such improvements in technology as direct current circuit breakers, magnetohydrodynamics, as well as improved methods for pollution control, could be utilized to lower costs and improve efficiency; therefore, the use of existing technology would give conservative results.

11. ESCALATION OF COSTS—All Study costs are based on 1970 cost data. These costs have been escalated to 1975 costs using specified escalation factors, so that comparison could be easily made with other feasibility studies. Escalation was assumed to be 5 percent per year which results in a ratio of 1.277 for 1975 costs/1970 costs.

12. COST OF MONEY—Until actual participation in construction of such a development is determined, it was believed to be impractical to adopt specific revenue requirements to use in calculating annual costs. Therefore, it was decided to derive capital costs based on investment per kw and provide a chart with a range of money costs which would enable individual entities to determine their own specific costs.

13. EAST-WEST TIES—In order to maintain the North Central Power Study within a scope which would afford a relatively straight-forward basis for analysis, closure of the North Central Power Study transmission system to afford further East-West tie capacity was not considered part of this Study. It did appear possible, however, that the East-West ties might be augmented by the early part of the Study period.

14. ENVIRONMENTAL REQUIREMENTS—The Study was conducted to meet all Federal and state requirements and any other reasonable requirements that could be foreseen. In special cases where it was believed an existing local regulation was impractical, a reasonable requirement still within the Federal laws was used.



CONCLUSIONS

II. CONCLUSIONS

In order to provide for future electric and other energy needs, the further development of the vast coalfields of the North Central region of the United States is almost a certainty. The development method studied in this report involves mine-mouth thermal generating plants for energy conversion and electric transmission for energy transportation. Water is involved in many of the plans to develop this coal resource, and the plans of this Study are no exception. The Study shows there is adequate, reasonable cost water available to provide cooling for the thermal plants under consideration. The abundant availability of resources with the economy of large-scale development may result in attractive economics for the cost of electric energy at the generating plants. The participants in the NCPS will compare their alternatives to this means of energy supply.

The long distances that separate the mine-mouth plants and the major load centers can be spanned reliably with modern ultra-high-voltage (UHV) transmission techniques. The transmission systems proposed could bring the benefits of strong UHV interconnections to the entire area and may assist UHV interregional interconnection between East and West.

The environmental impact of the plan described in this report has been given careful consideration and the proposals indicate a substantial need for programs and thought aimed at minimizing environmental impact. The low sulfur coal of the North Central area and the higher efficiency of large units studied combined with the most modern emission control devices could result in excellent air pollution control for the programs studied. However, there are many air pollution problems yet to be solved.

The overall environmental impact of the NCPS plan will be dealt with in full detail in later phases of this Study. Environmental statements will be prepared at that time.

The larger scale developments of mine-mouth generating plants at the coalfields of Wyoming, North Dakota and Montana coupled with UHV transmission may result in competitive prices for power and energy delivered to the load centers.

II A QUALIFICATIONS

In order to make an intelligent interpretation of the results of the North Central Power Study, important limitations and qualifications which directly affect the price of delivered power must be understood. The items listed below should be considered in comparing the use of mine-mouth powerplants with alternate power supply plans of individual utilities.

1.TRANSMISSION COSTS—In effect, the North Central Power Study provides a basis for comparison of the cost of transmission from coalfields to load versus the fuel transportation costs to distant sites. Due to time and guideline limitations, the results may reflect higher costs of delivered energy than would actually be experienced. Below are a few of the ways the transmission costs could be reduced:

a. The elimination of the very distant loads in Missouri at the 3,000-mw development could reduce transmission costs and lower the delivered cost of power. The timing of development could be delayed until other Eastern NCPS loads reached the 3,000-mw level with the Missouri loads not served until the 10,000- or 20,000-mw level is reached.

b. Use of point-to-point direct current lines from the coalfields to the farthest delivery points with lower voltage A.C. lines feeding intermediate loads could reduce transmission costs. For example, D.C. could be used from the coalfields to Minneapolis and St. Louis with 500-kv A.C. between these major load points to feed Omaha and Des Moines.

c. The NCPS transmission was planned with load area crossties to be practically independent of other transmission. By the time of NCPS development, it is believed that there will be UHV lines already connecting the large load centers in the eastern quarter of the Study area; therefore, some of the costs of crosstie reliability lines may be eliminated.

2. FUEL COSTS—It is expected that fuel costs for delivery of coal to load center plants will increase as rates for fuel transportation escalate in the future. However, once investment is made in the transmission lines, the cost of transmission of power by wire will remain practically constant over the life of the project. This factor should be considered in looking at an alternative local power supply.

3. ENVIRONMENTAL IMPACT—The environmental impact of locating large powerplants in the load areas versus the location of transmission lines for delivery of power from the coalfields must be looked at not only from the overall area viewpoint but also from the viewpoint of the individual utility in its own local area.

4. PARTIAL AREA PARTICIPATION—It may be more economical to develop a portion of the generating complex in other areas than Gillette-Colstrip such as the North Dakota coalfields. The total complex could be interconnected and might better reflect the best economical location of plants for delivery of power to users in certain areas such as Minnesota and Iowa.

II B RESULTS

The results of the Study as obtained from the work of the various committees and task forces are briefly summarized as follows: (Note: Construction costs are the sum of facility investment cost, property tax during construction, and interest during construction.)

1. Generation investment costs in the remote coalfield area will be approximately the same as costs in the areas of load concentration. Construction costs for a plant of two 500-mw units will range from $183/kw in 1970 to $234/kw in 1975. For a plant of two 1,000-mw

units, the price will range from $144/kw in 1970 to $183/kw in 1975. The higher costs in 1975 are based on projections of historical escalation factors. The cost of an emergency stock of coal is included.

2. Fuel costs in the Gillette-Colstrip area are about 12.5 cents per million B.t.u. in 1970 and are projected to be 16.0 cents per million B.t.u. in 1975.

3. Bus bar production costs which include cost of water, energy, and ash disposal, as well as O&M for plant and transmission, are:

	1970	1975
	mills/kwh	
2 or more 500-mw units	1.88	2.39
2 or more 1,000-mw units	1.57	2.01

4. Average transmission construction costs including substation and all transmission facilities required for delivery of power to eastern load centers are:

	1970	1975
	$/kw	
3,000 mw	321	410
40,000 mw	123	157

5. Figure II B-1 presents the total capital investment for generation and transmission on the eastern system.

6. Total costs for delivered power, including generation and transmission, are dependent upon location of load center and financing rates. For this reason Figure II B-2, which shows delivered costs of power for the eastern system, is included only for illustrative purposes. For details see the Economics Committee report.

7. For the western system the transmission construction costs to the Medicine Bow delivery can be summarized as follows:

Transmission Investment	1970	1975
	$/kw	
1,000 mw	87.00	111.00
10,000 mw	36.00	46.10

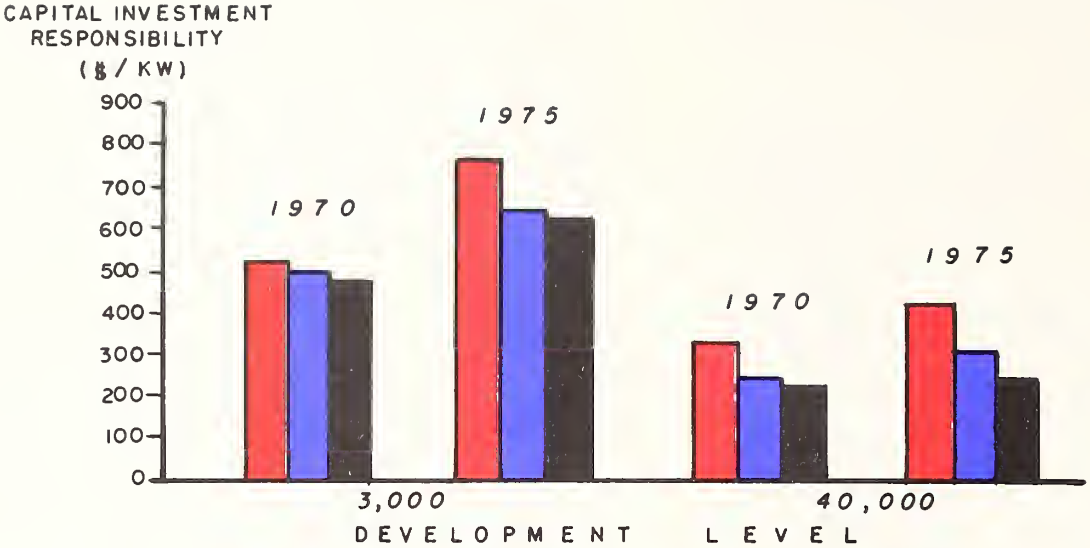
8. For the condition investigated, the use of hydro-pumped storage in combination with the mine-mouth plants raises the total investment approximately 8 percent and output capacity 7.5 percent. Hydro-pumped storage was included to make a portion of the NCPS output available at normal load factor since it was felt that many of the smaller users could not practically or economically utilize high load factor energy from the thermal plants. The investment requirement in hydro plant and all transmission added for the hydro-pumped storage is $387/kw in 1970 and $483/kw in 1975.

9. A brief comparative analysis was made on an alternative of moving generation from the Gillette-Colstrip site to a Beulah, North Dakota, site. This analysis was made only at the 3,000-mw generation level. Under the prescribed conditions, it was found that the additional generating costs at the North Dakota site would be higher than the savings in transmission. It was recognized that as an actual program developed it would perhaps be more practical to: (1) use a combination of generation at the two sites, or (2) serve certain individuals or groups of entities from the North Dakota site alone. However, it was not feasible because of limited time to study such combinations in detail in this initial phase of the Study.

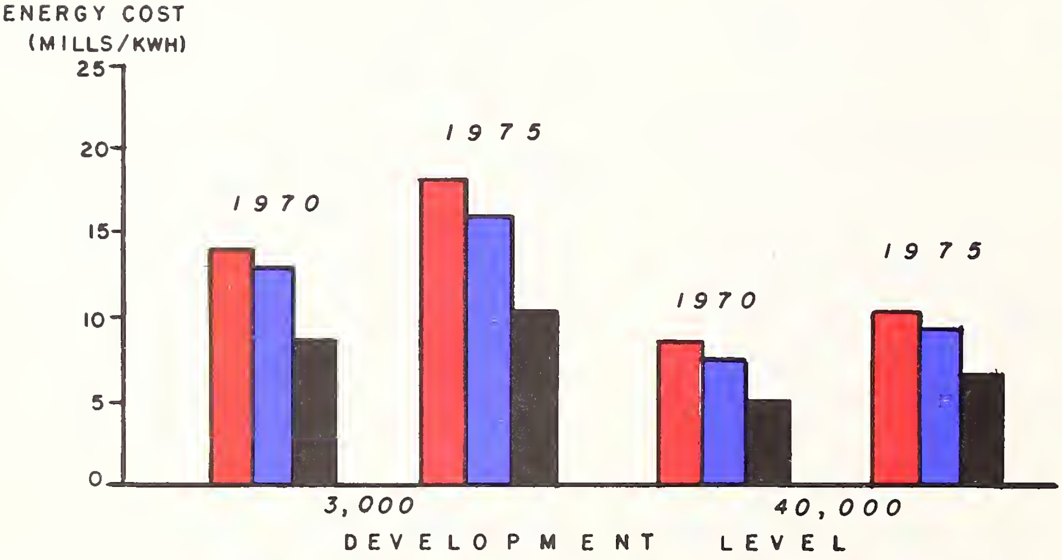
II C RECOMMENDATION

It is requested that all utilities participating in the North Central Power Study indicate in writing by July 1, 1972, their interest in pursuing the second phase of the Study as described under item 2 of the Criteria section of this report. Other entities not now participating in the Study are also invited to respond. Indication of interest should include the amount of power desired, timing required, and delivery point location. All letters should be addressed to:

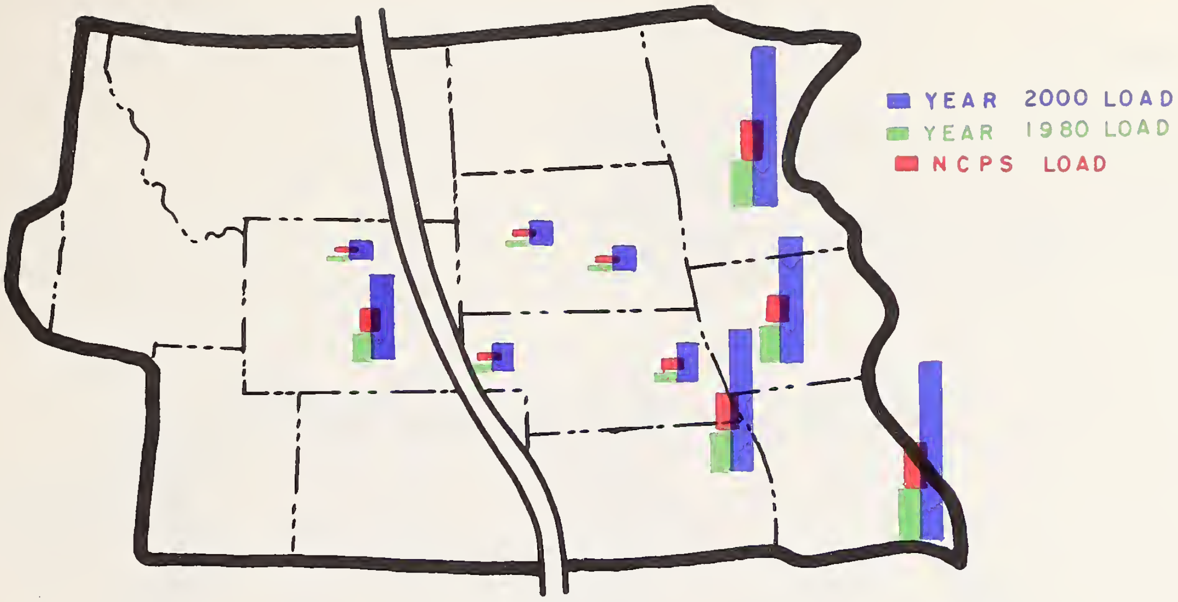
Steering Committee
North Central Power Study
Attention: NCPS Study Manager, William F. Graham
United States Department of the Interior
Bureau of Reclamation
Regional Office, Region 6
P. O. Box 2553
Billings, Montana 59103



CAPITAL INVESTMENT RESPONSIBILITY BY DELIVERY POINT
Figure II B-1



DELIVERED ENERGY COST BY DELIVERY POINT
Figure II B-2



L O A D

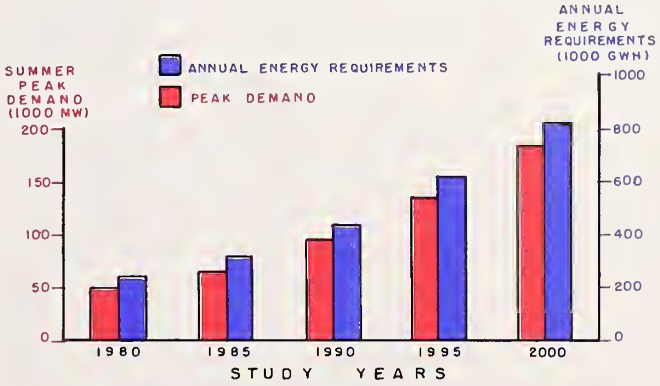
II D LOAD

An assumption basic to this Study is that use of electric energy in the North Central area will continue to increase in the years ahead. Recent history has shown electric consumption to double every 10 years—equivalent to a compound average annual rate of about 7 percent.

To establish load growth for the Study years and to provide data for locating the load centers, the Load Projection Committee worked from estimates of the bulk power suppliers in the area. These results are shown graphically on Figure II D-1 and agree well with the results from recent surveys by others.

The North Central Power Study area covers about 34 percent of the geographic area of the 48 contiguous states and in 1980 is predicted to have about 10 percent of the population and 10 percent of the electric power load. The load density in the eastern one-fourth of the Study area is high and comparable to the rest of the Midwest. In the western three-fourths of the area the load per square mile is very low and accounts for the low net value for the area. The NCPS area contains a wide range of load types—from predominantly rural in the west to dense urban-industrial in the east. The total area is expected to have a noncoincident summer demand of 51,000 mw in 1980 and 181,000 mw in 2000. Early in the Study it was decided that about one-third of the 1978-2000 load growth could be logically considered to be supplied from NCPS resources. This resulted in an ultimate development level of 53,000 mw. Consistent with basic Study criteria, the east and west load areas were established on each side of the present East-West ties.

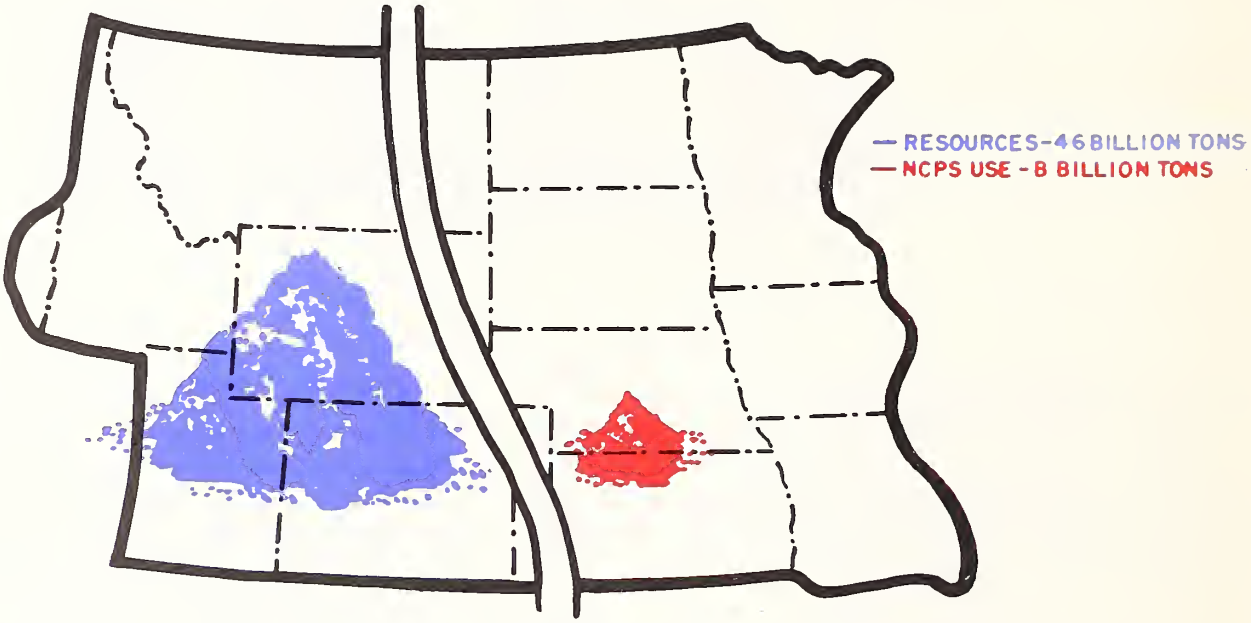
An analysis of the results of the Load Projection Committee shows an overall rowth rate of about 6.5 percent per year between 1980 and 2000—somewhat less than the historic national average but still with tremendous implications for those responsible for maintaining an adequate, reliable, low cost power supply. There are many factors that could change this growth rate, and a reduction would be the likely result should population growth diminish.



LOAD PROJECTION FOR TOTAL STUDY AREA
Figure II D-1

II E RESOURCES

Resource investigations were made of four separate categories and the results of these investigations are given below in summary form. The coal and water resources are given as they exist regardless of ownership or possible plans for other uses unless so noted.



COAL

II E-1 COAL

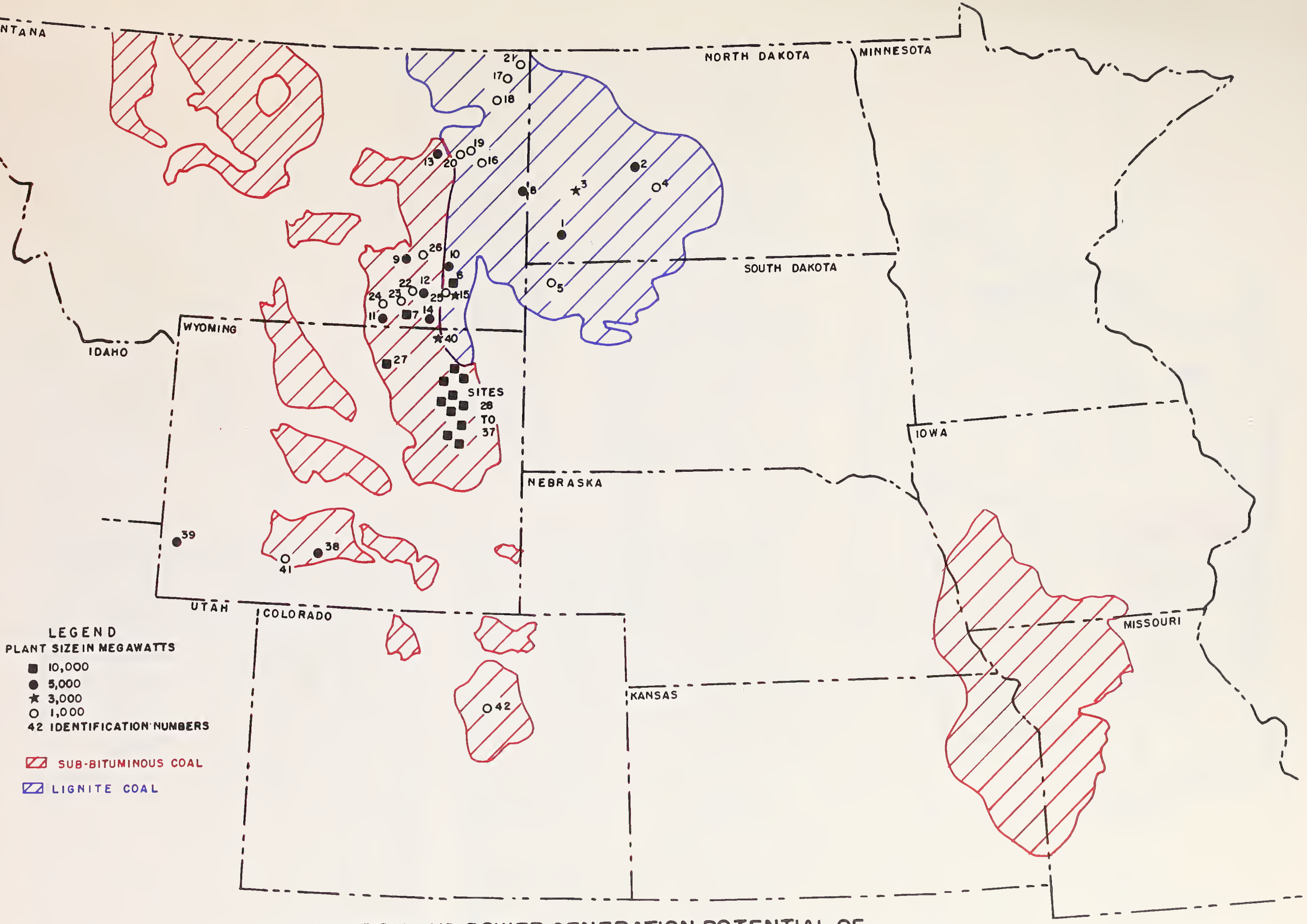
Vast quantities of lignite and subbituminous coal are readily accessible in the northwestern portions of the Study area. The Coal and Byproducts Task Force has located proven reserves of coal adequate to supply well over 200,000 mw of thermal generation which is only a small part of the total resource potential. This coal is of low sulfur content and for this reason is already being shipped to distant generating plants in ever-increasing quantities. Figure II E-1.1 shows the general location of the largest coalfields and potential plant sites and their size. Coal seam thickness varies from 25 feet to 150 feet at the selected sites with overburden thickness of from 10 to 200 feet. Reserves at these sites are adequate for at least 35 years of plant operation. The estimated 1970 cost of coal at the mine ranges from 11 to 20 cents per million B.t.u.'s as depicted on Table II E-1.1 with most of the coal in the low cost range. These estimated costs were developed through discussion with the energy companies, who hold many of the coal leases and United States Bureau of Mines personnel.

The competitive uses for this coal must be considered in any long-range plan. These include the present use in boilers at distant sites, and to future mine-mouth coal conversion processes that will produce gas, char, and chemicals. It is impractical to make firm estimates of the eventual size of these conversion processes at this time; however, there seems to be more than adequate coal for the NCPS plan and for other developments.

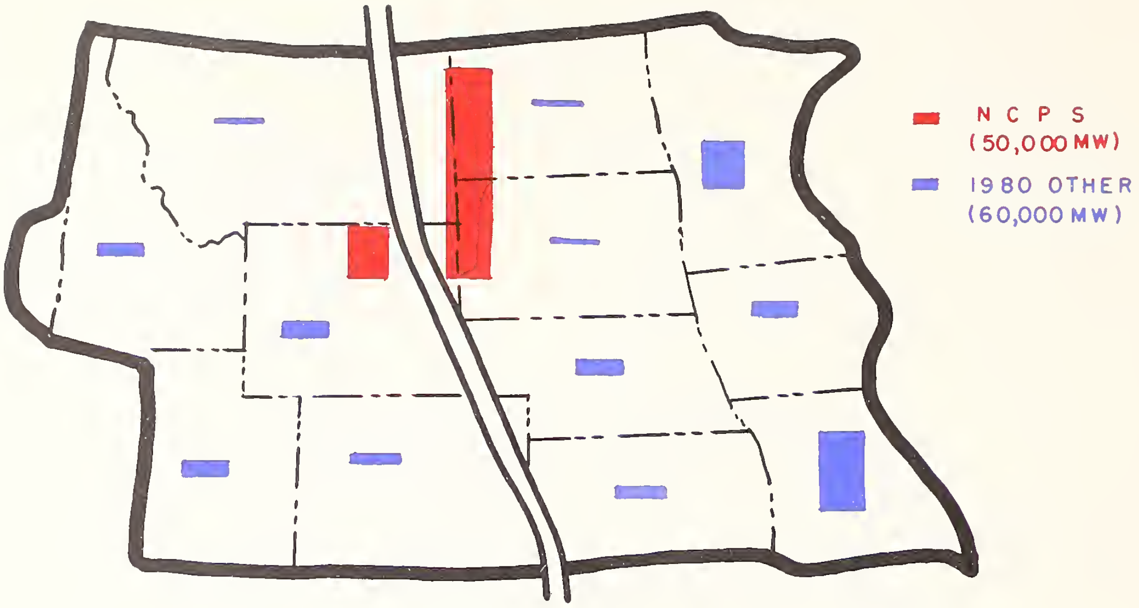
Table II E-1.1

COST OF COAL/B.T.U. AT FIELD LOCATIONS

Field Identification Nos.	Mine-Mouth Cost ¢/Million B.t.u.'s 1970	1975
1-3	12.5 - 14	16.0 - 17.9
4-5	13 - 15	16.6 - 19.1
6-15	11 - 13	14.0 - 16.6
16-27	12 - 14	15.3 - 17.9
28-37	11 - 12	14.0 - 15.3
38-41	15 - 18	19.1 - 23.0
42	15 - 20	19.1 - 25.5



LOCATION AND POWER GENERATION POTENTIAL OF STRIPPABLE COAL DEPOSITS IN NORTH CENTRAL POWER STUDY AREA
Figure II E-1.1



THERMAL GENERATION

II E-2 THERMAL GENERATION

The Thermal Generation Task Force has developed the costs of large units using actual bids and manufacturers' information. The Task Force has developed complete capital and operating costs for pairs of 500-mw and 1,000-mw units. It was determined that no further unit cost economy would result if more than two units were considered in a common plant. The economy of scale is illustrated by comparing the capital cost of two 1,000-mw units at $124/kw to the cost of two 500-mw units at $158/kw based on estimated 1970 costs. These costs do not include property taxes and interest during construction. The exact location of thermal plants was governed by the location of the most promising coal sites.

Dry-type cooling would have an additional capital cost over the equivalent wet-cooling cost of about $14 per kw; in addition, the heat rate of units with dry-type cooling is about 10 percent less favorable than wet-cooled units and O&M costs are higher. The higher heat rate is due to the increased turbine back pressure with dry cooling; however, further work on turbine design may improve efficiencies notwithstanding this high back pressure. The Pollution Control Task Force has analyzed the cooling options in depth and has concluded that delivered water, in all but the smallest development, would have to cost more than the prices shown in the Water Supply Task Force report to exceed the cost penalties associated with dry-type cooling. If and when dry cooling economics are improved, cooling water planned for thermal generation may be used elsewhere.

Forced outage rates and maintenance outage rates were based partially on experience as reported by Edison Electric Institute but adjusted and averaged for NCPS conditions. Unit availability based on these two outage rates was reported to be 87 percent for 500-mw units and 85 percent for 1,000-mw units. Additional generating units for the maintenance component of outage rates were included in the total installed thermal generation.

The costs of precipitators and wet-induced draft cooling towers are separated to enable consideration of different data by NCPS members in studying alternatives. Basic data are also supplied to enable the evaluation of dry-type cooling if this alternative is selected. Table II E-2.1 is included to present the most important results of the Thermal Generation Task Force.

Table II E-2.1

THERMAL GENERATION CAPITAL COSTS

	Unit Size MW	1970	1975
1. Generation Capital Costs in $/Net KW	2 - 500	$158.00	$202.00
Generation Capital Costs in $/Net KW	2 - 1,000	124.00	158.00
2. The generation costs above include these amounts in $/net kw for:			
Precipitator -	2 - 500	8.50	11.00
Induced draft wet cooling tower -	2 - 500	8.50	11.00
Precipitator -	2 - 1,000	7.00	9.00
Induced draft wet cooling tower -	2 - 1,000	7.00	9.00
3. For dry cooling substitute these capital costs for the above wet cooling tower costs $/net kw	2 - 500	23.00	29.00
For dry cooling substitute these capital costs for the above wet cooling tower costs $/net kw	2 - 1,000	21.00	27.00

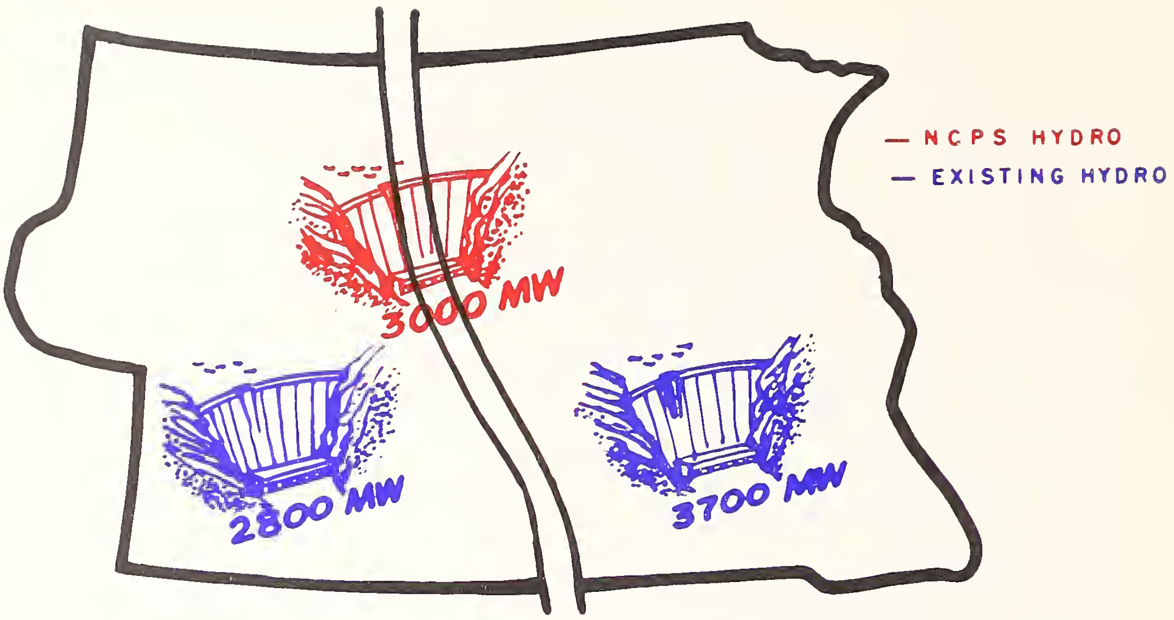
(Not including IDC or ad valorem taxes during construction)

THERMAL GENERATION OPERATING COSTS

	Unit Size MW	1970	1975
1. Operation and Maintenance (not including Administration and General Charges)			
Using Wet Cooling	2 - 500	.45 mill/kwh	.57 mill/kwh
Using Wet Cooling	2 - 1,000	.25 mill/kwh	.32 mill/kwh
With dry cooling add these O&M amounts to the wet cooling O&M costs:	2 - 500 mw	.053 mill/kwh	.067 mill/kwh
With dry cooling add these O&M amounts to the wet cooling O&M costs:	2 - 1,000 mw	.031 mill/kwh	.039 mill/kwh
2. Ash Disposal Costs			
Based on 10 percent ash in mills/kwh	either size	.10	.13
Based on 20 percent ash in mills/kwh	either size	.20	.26
3. Land Reclamation (averaged estimate)			
Cost is expressed in ¢/ton of coal mined		2.5¢/ton	3.2¢/ton

4. Net Heat Rate of Units with Wet Cooling, 500 mw, 9,500 B.t.u./kwh
Net Heat Rate of Units with Wet Cooling, 1,000 mw, 9,100 B.t.u./kwh
Net Heat Rate of Units with Dry Cooling, 500 mw, 10,400 B.t.u./kwh
Net Heat Rate of Units with Dry Cooling, 1,000 mw, 10,000 B.t.u./kwh

(.85 plant factor and 5 percent annual escalation to 1975)



HYDRO

II E-3 HYDRO

The Hydro generation Task Force has investigated potential conventional hydropeaking and pumped storage sites through the Rocky Mountain and Missouri River main stem portions of the NCPS area. Early in the Study the Steering Committee directed that other potential sites near area load centers would not be studied in NCPS but could be considered in alternative plans of the participants. Thirty different plant locations were identified, given a capacity rating, and estimates were made of their construction and O&M costs.

As the Study progressed, the Steering Committee set additional important limits for the Task Force: only 3,000 mw of hydropeaking was to be developed concurrently with the eastern base load thermal system of 40,000 mw, and due to load duration characteristics of the area, 8 hours daily of peaking was to be required. These limits resulted in the selection of the 1,760-mw Cutler Park-Rockwood and 1,240-mw Sheep Mountain pumped storage sites in Wyoming. Figure II E-3.1 shows the location of these sites with respect to the potential thermal generating sites.

The major features of the two selected sites are listed below:

CUTLER PARK-ROCKWOOD SITE

This site is located on the Tongue River west of Dayton, Wyoming. The proposed development includes construction of a concrete dam on the Tongue River (Rockwood) and an earthfill dam and dike on Cutler Creek. The proposed plan of development and its estimated cost considered facilities based on the following data:

Pumping Generating Plant—1,760 mw
  No. of Units—4
  Size of Units—440 mw
  Head (Maximum Static Head on Unit)—900 feet
Plant Operation
  Pumping Period—14 hours
  Peaking Period—8 hours
Estimated 1970 Cost—$139/kw
Estimated 1970 Annual O&M Cost—$1.64/kw (excluding cost of pumping energy)

SHEEP MOUNTAIN SITE (above Buffalo Bill Dam)

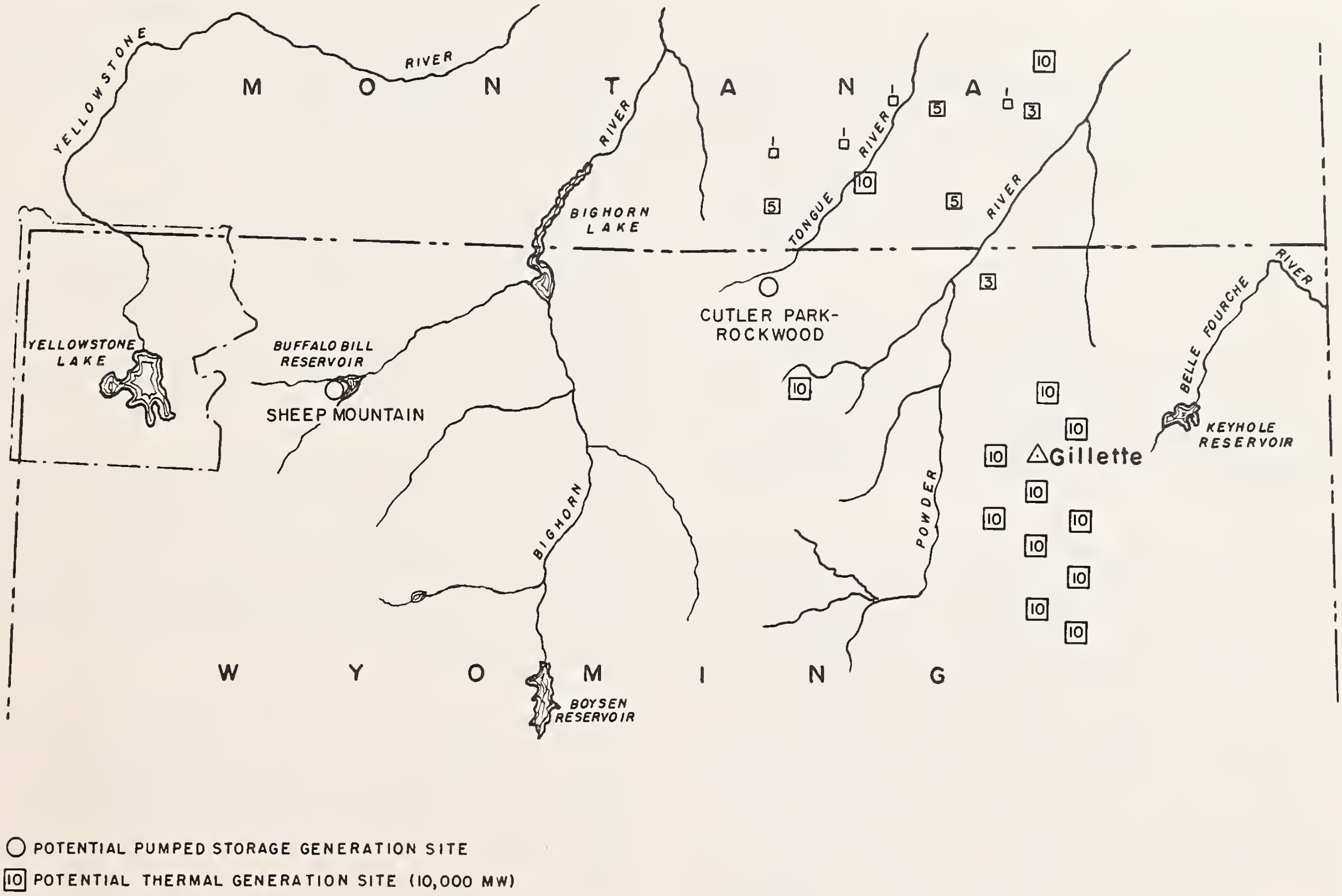
The proposed development plan for the Sheep Mountain impoundment above the existing Buffalo Bill Reservoir near Cody, Wyoming, provides for active storage of 6,900 acre-feet of water. The structural height of the proposed dam is 355 feet with an elevation at the top of 6,785 feet. The following data were considered in deriving the estimated cost for the pumped storage development utilizing Buffalo Bill Dam and the proposed Sheep Mountain Dam:

Pumping Generating Plant—1,240 mw
  No. of Units—3
  Size of Units—413 mw
  Head (Maximum Static Head on Unit)—1,510 feet
Plant Operation
  Period—14 hours
  Peaking Period—8 hours
Estimated 1970 Cost—$175/kw
Estimated 1970 Annual O&M Cost—$1.50/kw (excluding cost of pumping energy)

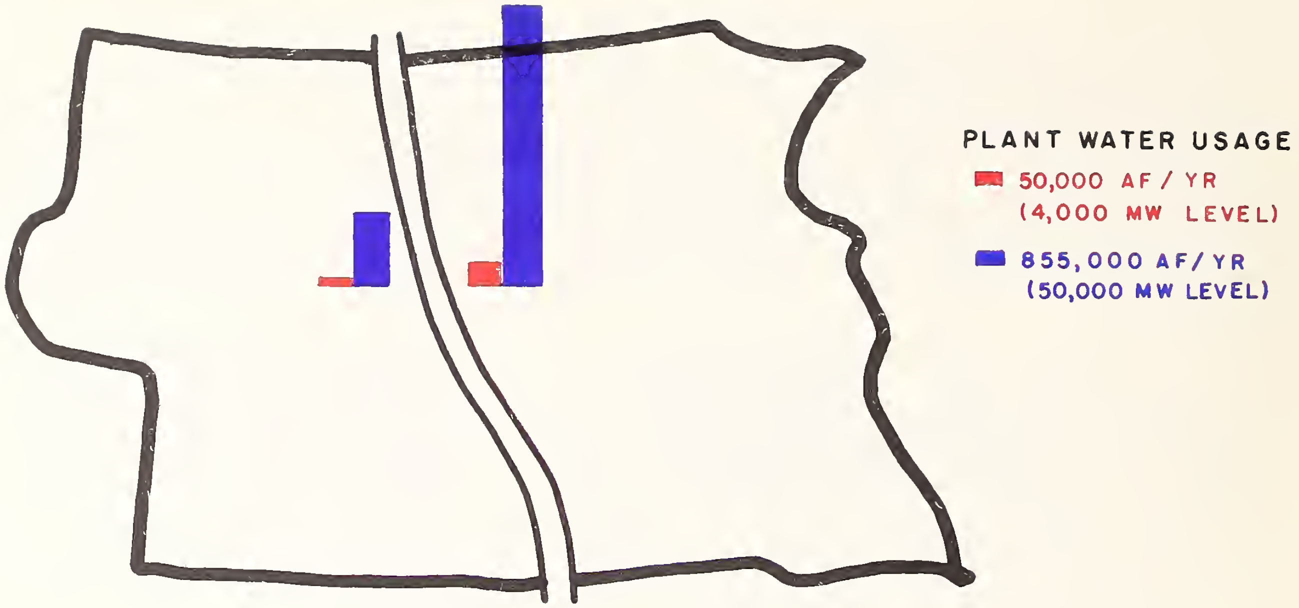
The 8-hour peaking requirement was selected because the area hourly load curve shows a pronounced flat peak with the load near the maximum for a prolonged period. This requirement results in pumped storage plants with a high cost/kw because of the increased reservoir sizes over those associated with plants with a short peak period.

The principal benefit of a pumped storage plant is its ability to convert low cost offpeak energy and capacity to higher value on peak energy and capacity. The costs associated with the pumped storage plant including plant investment, expenditures of 3 kwh of energy for return of 2 kwh, and the cost of added transmission needed for these plants must be clearly less than the incremental benefits. The requirement for transmission facilities placed considerable economic burden upon the pumped storage plants which are remote from the load. The transmission costs could be considerably reduced and the feasibility of these pumped storage sites improved if thermal-hydro blending was applied to the loads nearest Wyoming.

The Corps of Engineers has potential conventional peaking and pumped storage sites on the main stem of the Missouri River that aggregate 2,000 to 3,000 mw, of which about 1,200 mw was identified for this report. This main stem hydro may reduce transmission costs significantly and should be investigated further when sites and site costs are better defined.



POTENTIAL PUMPED STORAGE AND THERMAL GENERATION SITES
Figure II E-3.1



WATER

II E-4 WATER

The Water Supply Task Force was organized to explore water availability in quantities suitable for large generating plant requirements. Wet cooling appears to be economical and practical. The Water Supply Task Force has located adequate water for the scope of development contemplated. Dry-type cooling, while having recognized advantages, does not presently appear as a preferred method of cooling over the wet cooling tower.

The Task Force identified and computed the cost of water delivered to potential coalfields located by the Coal and Byproducts Task Force. The results applicable to the selected coalfield in the vicinity of Gillette, Wyoming, are presented in Table II E-4.1.

This table is based on 28 cfs consumption per 1,000 mw and is considered to be a conservative use rate that may be reduced when designs are refined. Minimizing the water use is desirable since NCPS water supply is relatively expensive. The Pollution Control Task Force has made a comparative analysis of cooling ponds, dry-type cooling, and wet tower cooling methods which indicates that cooling ponds may be more economical and consume less water than the cooling towers. Dry-type cooling reduces water consumption to a minimum but has offsetting disadvantages.

While the cost per unit of water is reduced by large use, there are finite limits on the single source presented by Table II E-4.1. For purposes of this study, quantities taken from the Bighorn River at Hardin, Montana, were limited to 550,000 acre-feet annually; however, total potential annual supplies in the Gillette-Colstrip area are estimated to be 1.8 million acre-feet. There appears to be adequate water for foreseeable NCPS and other industrial uses in the Gillette-Colstrip area.

Water supply costs include the investment and operating costs for the aqueduct, pumping plants, receiving end 3-day storage, O&M, and depreciation as well as the cost of water at the input to the aqueduct system. Figure II E-4.1 describes the general alignment of water conveyance facilities in the Gillette-Colstrip area.

For some coal sites it may be more economical to haul coal to water resources than pipe the water long distances; however, the coal haul must be short since water delivery costs are less than 0.2 mills per kwh, and the additional cost of coal haulage would have to be less than 40 cents per ton to be competitive.

Pumping energy was assumed to cost 4 mills per kwh, including the cost of transmission but without a component for demand. This rate was established with the assumption that the pumping load will be interruptible. The interruptible pumping load is made possible by designing the water supply system with 3-day reservoirs at the delivery terminals. The electric power transmission facilities needed to supply the pumping system between the Bighorn River and Gillette are shown in the Transmission Committee plans.

The 3.463 percent interest rate used in the determination of annual costs for water supply is the rate authorized by the 1958 Water Resources Act and which water resource agencies are currently applying. Inasmuch as the participants are comparing costs of the NCPS complex with those of their own alternatives which will reflect each participant's own revenue requirements, an alternate approach would be to assume joint financial support of water supply with the revenue requirement of 11.3 percent derived for the overall complex. The effect would be to increase energy costs by approximately 10 percent in the largest development.

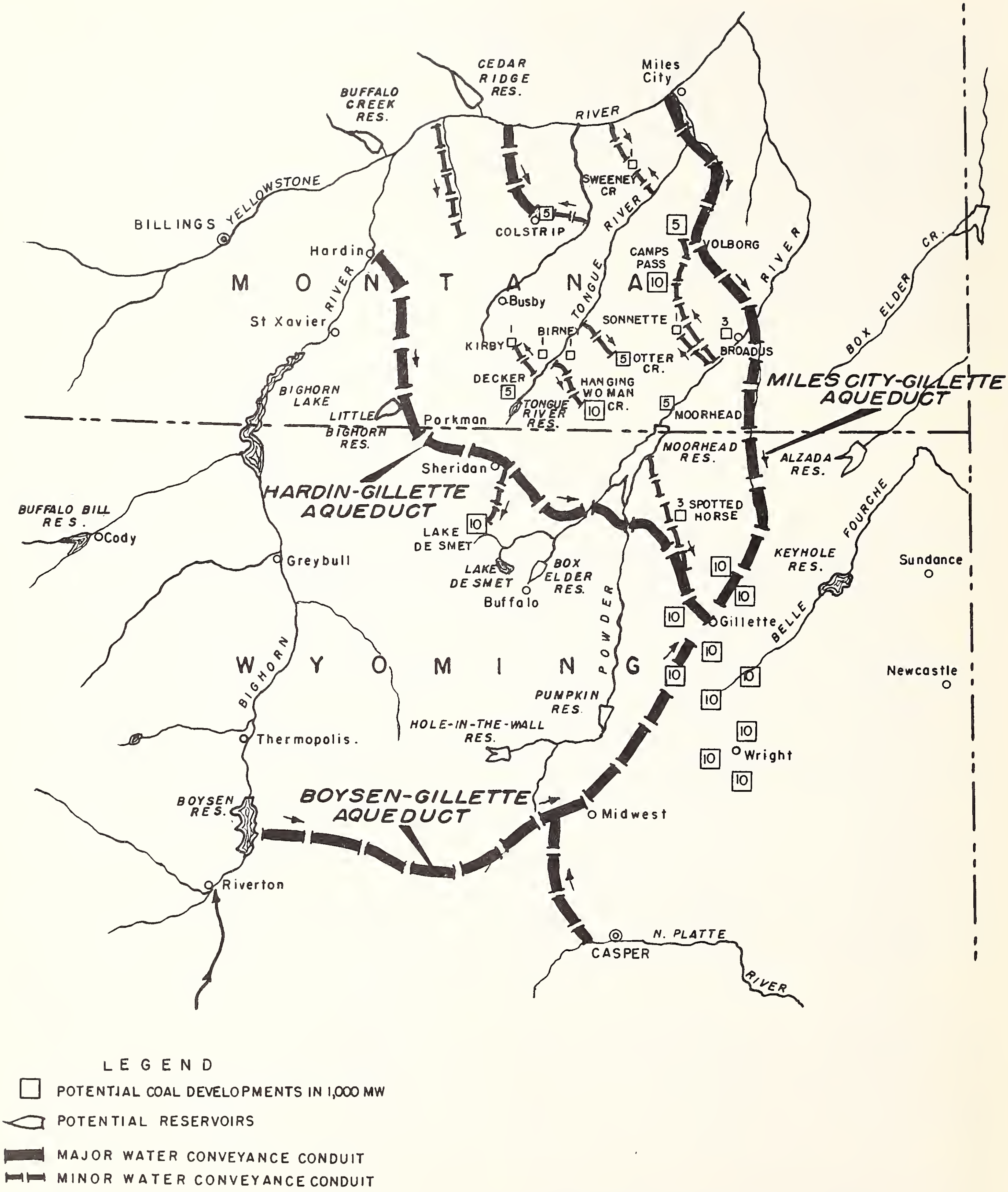
Table II E-4.1

UNIT COST OF WATER DELIVERED IN GILLETTE AREA
(Oct. 1970 Price Level)

Aqueduct Water Deliveries and Unit Costs

MW Installed	Water for Generation A.F./Yr. 1/	Cost of Water Per Acre-foot (Steam Plant Portion of Delivered Water) 100%	67%	50%	33%
3,000	50,000	$170.00	$149.00	$133.00	$114.00
6,000	103,000	133.00	113.00	102.00	91.00
8,000	137,000	118.00	102.00	94.00	85.00
13,000	212,000	101.00	90.00	85.00	79.00
15,000	257,000	96.00	86.00	82.00	78.00
20,000	342,000	89.00	82.00	79.00	77.00
23,000	394,000	86.00	80.00	78.00	76.50
25,000	427,000	84.00	79.00	77.00	76.00
30,000	510,000	82.00	78.00	76.50	76.00
40,000	685,000	79.00	76.50	76.00	76.00
50,000	855,000	77.00	76.00	76.00	76.00

1/ Based on 28 c.f.s. per 1,000 MW installed capacity as suggested in Chapter X of National Power Survey.



WATER CONVEYANCE IN THE GILLETTE-COLSTRIP AREA
Figure IIE-4.1

II F TRANSMISSION

The Transmission Committee developed a transmission system for transporting the energy from the mine-mouth thermal generating plants to the load centers. Systems developed had Gillette area generation levels of 3,000, 10,000, 20,000, 40,000, and 43,000 mw for eastern delivery, and a western delivery point for 1,000, 3,000, and 10,000 mw generation levels. Eight load centers were defined in the east and one transmission delivery point for the west. Power delivery to the west was also made directly from the generating complex.

For best economy and minimum impact on the environment, 765 kv, the highest commercially available A.C. transmission voltage, was selected for the eastern system and 500 kv for the smaller western system. The need to maximize the utilization of the extensive and costly transmission system was met by holding the transmission load factor over 91 percent for the largest developments. This required a total of 4,500 mw of additional generation for maintenance of units for the east and west systems in the ultimate development. The reliability of a supply system as large as this is exceedingly important, and the criteria of Western Systems Coordinating Council and Mid-Continent Area Reliability Coordination Agreement were considered in developing all stages of the systems. Figure II F-1 shows the general routing and extent of the ultimate development transmission systems. Consistent with Study criteria, D.C. transmission was not applied because the apparatus necessary for practical multipoint delivery is not commercially available. It is recognized that developments between now and the time NCPS transmission must be committed may alter this position, and advanced transmission technology may reduce transmission system costs.

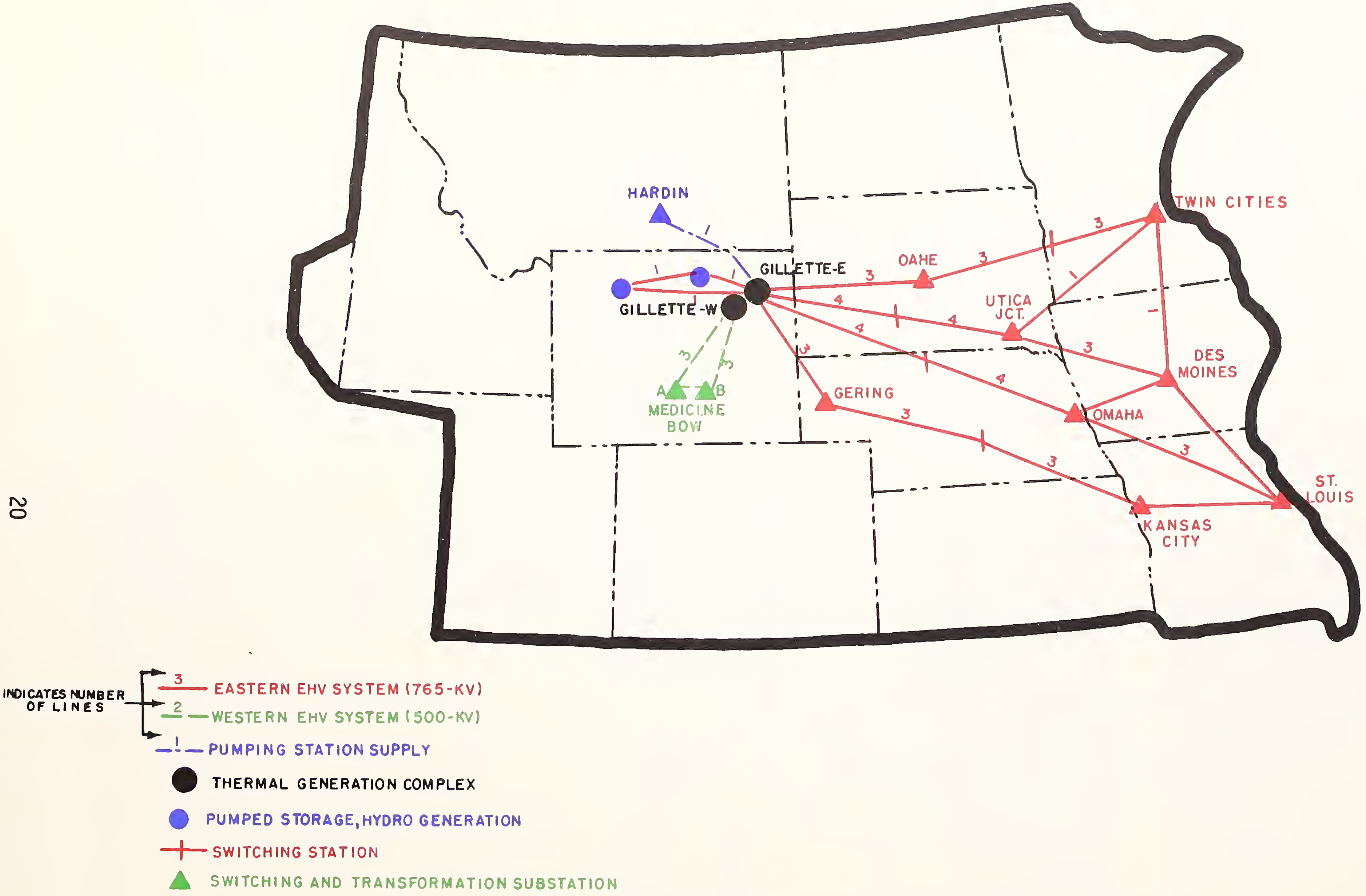
Table II F-1 provides the results of the costing for the selected transmission system for each level of development. The unit cost for transmission shows considerable reduction with the larger levels of development.

Table II F-1

TRANSMISSION UNIT COSTS

Generation Level (MW)	Estimated 1970 Costs (Millions of $)	Unit Cost ($ Per KW Transmitted) 1970	1975	Decrease in Unit Cost* (%)
Eastern System				
3,000	812	270.7	345.3	-
10,000	1,461	146.1	186.4	46.0
20,000	2,319	116.0	148.0	20.6
40,000	4,148	103.7	132.4	10.6
43,000	4,645	108.0	137.9	-4.2
Western System				
1,000	74	74.0	95.0	-
3,000	154	51.2	65.2	30.7
10,000	304	30.4	38.8	40.6

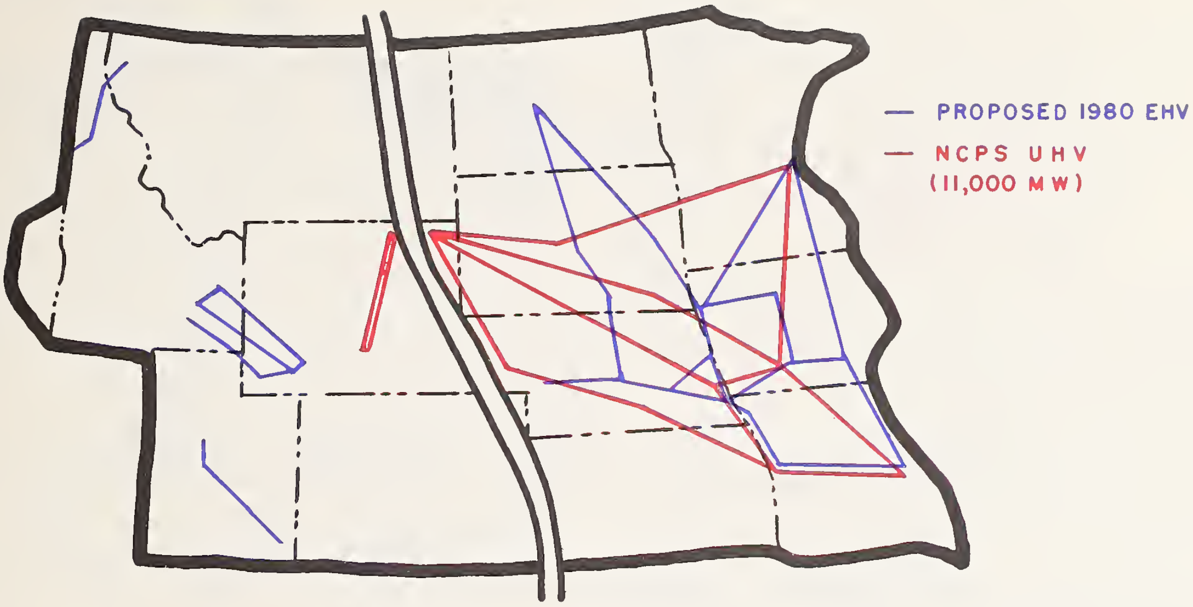
* Relative to next lower generation level.


HARDIN
GILLETTE-E
GILLETTE-W
MEDICINE BOW
A
B
OAHE
UTICA JCT.
TWIN CITIES
DES MOINES
OMAHA
GERING
KANSAS CITY
ST. LOUIS
1
1
1
1
1
3
3
3
3
3
3
3
3
3
3
3
4
4
4
4
INDICATES NUMBER OF LINES
3 EASTERN EHV SYSTEM (765-KV)
2 WESTERN EHV SYSTEM (500-KV)
1 PUMPING STATION SUPPLY
THERMAL GENERATION COMPLEX
PUMPED STORAGE, HYDRO GENERATION
SWITCHING STATION
SWITCHING AND TRANSFORMATION SUBSTATION

TRANSMISSION SYSTEM-ULTIMATE DEVELOPMENT

DEVELOPMENT LEVEL - 10,000 MW WEST, 43,000 MW EAST

Figure II F-1



TECH STUDIES

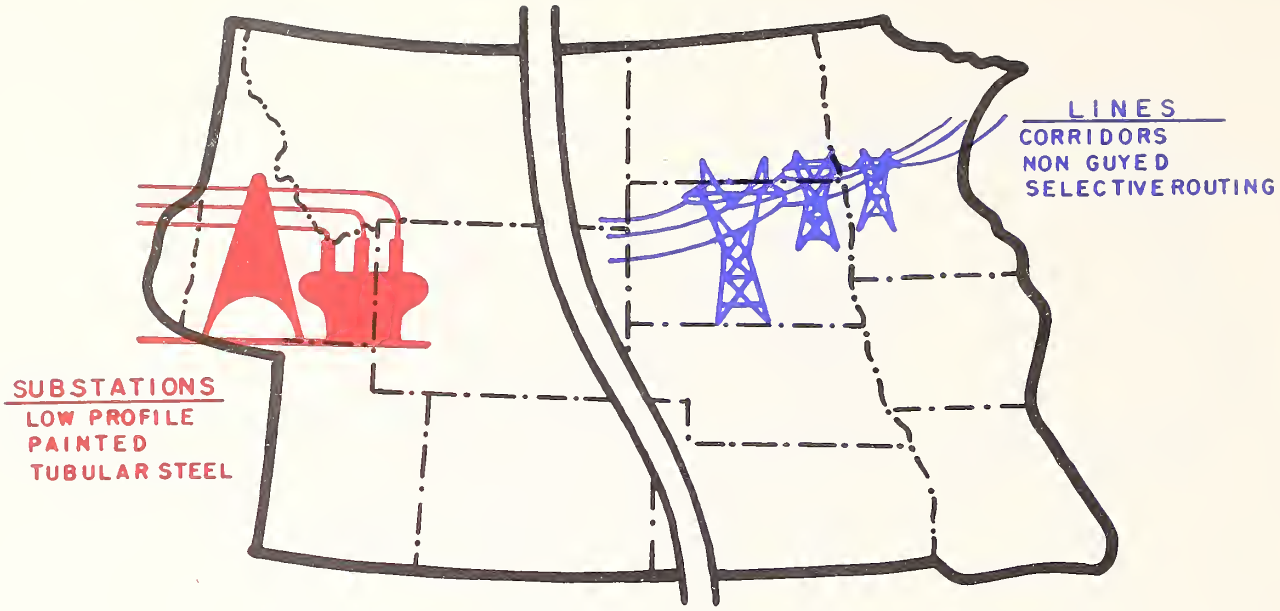
II F-1 TECHNICAL STUDIES

The Technical Studies Task Force designed transmission systems for the several development levels. To aid in the design of these systems computer load flow studies were made and the line loading and phase angle between the sending and receiving busses checked. Transmission was adjusted so that phase angle was held to 30 degrees for normal system conditions and 42 degrees for outages. This criteria was used in lieu of full stability studies, in consideration of the limited time schedule for this Study. Loading on the 765-kv lines was held below 3,500 mw for normal conditions and 5,000 mw under outages. Compatability of the NCPS plan with the expected underlying transmission was examined and judged to be acceptable.

Series compensation of the eastern transmission system was essential for practical and economic reasons. To obtain the same low impedance and phase angle as with the 80 percent compensated system, but without compensation, would more than quadruple the lines required.

The 14—765-kv lines in the eastern system required to deliver ultimate output of the generating complex were arranged in four corridors and are capable of transmitting 43,000 mw of generation within phase angle and line loading criteria with any two lines out of service.

Transmission system capacity losses in the eastern system were calculated to be 3.3 percent in the 3,000-mw development and 6.7 percent in the ultimate development. The western system had a shorter transmission system and capacity losses ranged from .9 to 1.8 percent. Generation for normal plant maintenance was carried at the generation site. For forced transmission and generation outages, reserves were to be carried in the load area. The NCPS plan would not increase installed reserves requirements over local generation supply alternatives in the eastern area.



DESIGN AND LOCATION

II F-2 DESIGN AND LOCATION

The Design and Location Task Force provided designs and costs for the transmission lines and substations. System reliability, environmental impact, and costs were considered along with other technical requirements in arriving at the designs.

Transmission towers were proposed to be unguyed with an improved appearance lattice-type galvanized steel design. The self-supporting feature would reduce the amount of land taken for each tower which is particularly important on lands under cultivation. The Task Force has also determined it would not be necessary to fence the right-of-way for the 765-kv transmission which means that the bulk of the ROW for the lines could remain in the present land use pattern. Four transmission corridors were planned for the largest developments. These corridors, which could eventually include other utility services, were chosen to minimize environmental impact yet provide acceptable system reliability for conditions where a single event could knock out multiple lines. These corridors were located to avoid national forests, parks, and other areas where the corridor might present an objectionable sight.

Transmission line costs comprise about 50 percent of the cost of the eastern system. Unit costs for the two voltages used in NCPS are shown in Table II F-2.1 along with the phase conductor size and configuration.

Substation appearance design was based on low profile, non-lattice decoratively painted steelwork. For reliability and low cost,the ring bus or breaker and one-half switching schemes were used throughout the system.

Switching stations or substations would be located so that no line section would exceed 300 miles and all reactive compensation would be located at these stations. Three hundred miles was chosen to limit switchgear duty and to keep the loss of transmission per line section to a reasonable level. A sample of the cost of the various elements in a 765-kv substation is included on Table II F-2.1.

ABBREVIATED COST TABLE FOR TRANSMISSION FACILITIES Table II F-2.1

Transmission Line Costs (Single Circuit AC)	1970	1975
(1) 765 kv (4-1,272 MCM/Phase)	$230,000/Mile	$293,000/Mile
(2) 500 kv (3-1,113 MCM/Phase)	130,000/Mile	165,880/Mile
Costs of Typical 765-kv Substation Equipment		
Autotransformer, 765/345 kv, 1,200 MVA	$2,700,000	$3,445,000
3 - 765-kv bays w/PCB	3,300,000	4,211,000
1 - 765-kv, 600-MVAR reactor	1,800,000	2,296,000
765-kv, 2,000-MVAR series compensation	16,440,000	20,977,000

II G ENVIRONMENTAL

The electric utilities participating in the North Central Power Study have endeavored, on the basis of historical load growth data, to project to the year 2000 the requirements for electric power in the 13-state area covered by this Study. Unless there is some public policy decision to the contrary, the utilities assume that whatever the future requirements may be, they must fulfill their responsibilities for meeting them in the most efficient and economical way. They further recognize that any definition of efficiency and economy must include full consideration of all costs, including the effects on our environment, and that plans for meeting electric energy requirements must include provisions for minimizing adverse effects on the natural environment.

Accordingly, in projecting future requirements and outlining the magnitude of the facilities which would be required to meet them, the participating utilities recognize that these requirements must be met by using advanced technologies which will have far less effect on the environment than the technologies which have been available to the industry to date.

The electric power industry is concerned about protection of our environment. In addition to the desires of the industry and the requirements of law, there is a substantial body of public opinion which simply would not tolerate the large additions to power production and delivery facilities which appear to be required between now and the year 2000 if these additions were proposed without very substantial improvements in technology.

Perhaps the first question to be considered is whether the additional requirements which this Study forecasts represent real needs. This question is not one to which the participants can give a categorical answer. Historically, the largest single requirement for electricity in this region has been for industry, including the principal industry of agriculture. Other major categories include the use of electric energy by residential consumers and by commercial establishments. The participants in this Study have a basic responsibility for supplying electric energy at the time it is needed. The participating power systems also are in no position to decide unilaterally that consumers will or should decrease the rate at which they use electric energy. The rate of increase assumed in the Study approximates the rate of increase which has been a matter of historical fact in the United States since early in this century. If the people of this country are not using electric energy in the future as freely as they have in the past, there would need to be public policy decisions to this effect.

There has been a recent notable increase in the development of new processes and expanded use of old methods to improve environmental protection in a wide variety of applications such as materials recycling, waste water treatment, and air treatment. All of these processes consume energy and the electric power industry will be called upon to serve the bulk of this expanded energy use.

Electrical energy ranks among the cleanest, most efficient and flexible forms of energy. It is in the production of this energy, however, that major technological improvement is needed.

The participants in the Study recognize that any additional facilities must conform to all Federal and state requirements with respect to environmental protection. The participants are in the process of modifying existing facilities so as to bring them into compliance with the new Federal and state requirements. The results of these steps cannot be immediate, simply because it takes a period of years to do the necessary engineering studies and obtain and install the equipment.

The participants advocate the acceleration of effective research and development programs in the following areas pertaining to fuel burning plants to meet the objectives of providing adequate, reliable, and economical electric energy with maximum environmental protection:

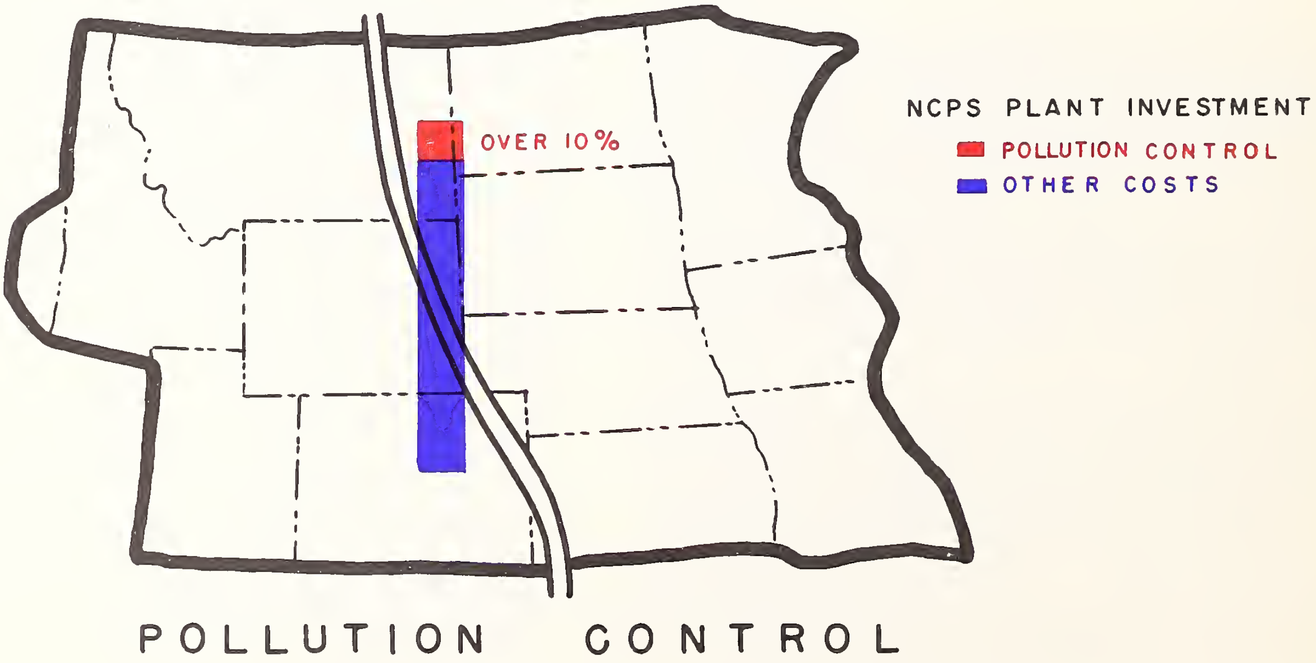
1. The accelerated development of new technologies to convert coal and lignite to electric energy which will be much more efficient than present methods. For example, magnetohydrodynamics holds the promise of converting coal and lignite to electric energy with efficiencies approximating 60 percent, compared to efficiencies of present technology of about 30 to 35 percent. Development of MHD could permit the industry to produce the electric energy required with a lower rate of use of coal and lignite, thus also producing far less fly ash, sulfur, and other effluents. Obviously, this would also extend our finite solid fuel resources.

There is only a small effort presently being expended in the United States on the development of MHD. The Electric Research Council Task Force on MHD has under development a national R&D program for MHD over a 10-year period. This, together with other programs for fuel cells and other new energy conversion technologies, should have added support.

2. Promising results are reported in the development of technology to convert coal and lignite to petroleum products through gasification and liquification processes. Research and development work should be expedited to determine whether these or modified processes can produce an economical "clean" fuel for use in boilers to produce electric power. It seems timely to undertake a concerted and vigorous "systems approach" to the matter of converting coal and lignite to a variety of other types of fuels and energy which maximize the overall utilization of these energy resources.

3. The most urgent research and development requirements with respect to the immediate, short-range needs relate to reducing to the minimum environmental effects using presently available technologies. Included is the development of practical systems to remove sulfur and nitrous oxides from stack gases, the development of ways to dispose of the waste heat from steamplant condensers and the reclamation of strip-mined land. Efforts are already underway by utilities, manufacturers, and Government, but more are needed.

One of the main conclusions to be drawn from the North Central Power Study is that much greater effort must be initiated immediately to develop technologies for the production and delivery of electric energy that will have less adverse impact on the environment, and at the same time make more efficient use of our finite resources. In pursuing these objectives, those responsible for developing and supplying electric power equipment and for producing and delivering electric energy should also maintain the goal of lowest possible costs for electric energy delivered to the ultimate consumer.



II G-1 POLLUTION CONTROL

This Task Force has examined the methods and costs of controlling air and water pollution to state and Federal standards. Its investigation into water pollution discusses the merits of cooling ponds, wet cooling towers, and dry cooling towers. Although wet cooling towers were selected early in this Study, the Task Force has indicated there may be a savings in water and cost by the use of cooling ponds. These ponds, which must have a surface area of about 1 acre per mw, become practical because of abundant low cost land near the plant sites. An additional benefit of the cooling pond may be its potential for recreational use.

The Task Force has found the costs for precipitators needed for air quality maintenance and has estimated the cost of ash disposal. Fly ash collection to 99.5 percent efficiency using coal from the vicinity of the development will require special precipitator installations that can work properly with low sulfur coal involved. The coal from the Gillette-Colstrip area may preclude the need for sulfur oxide removal because of its low sulfur content. Nitrogen oxide control to 500 ppm will probably be possible without additional costs. It is recognized that the same high standards of pollution control will be necessary in the remote coalfields as in densely populated load areas.

Some areas have found markets for fly ash, but the remoteness of the selected sites in NCPS may make marketing impractical. Integration of coal stripping and ash disposal may yield minimum ash disposal costs.

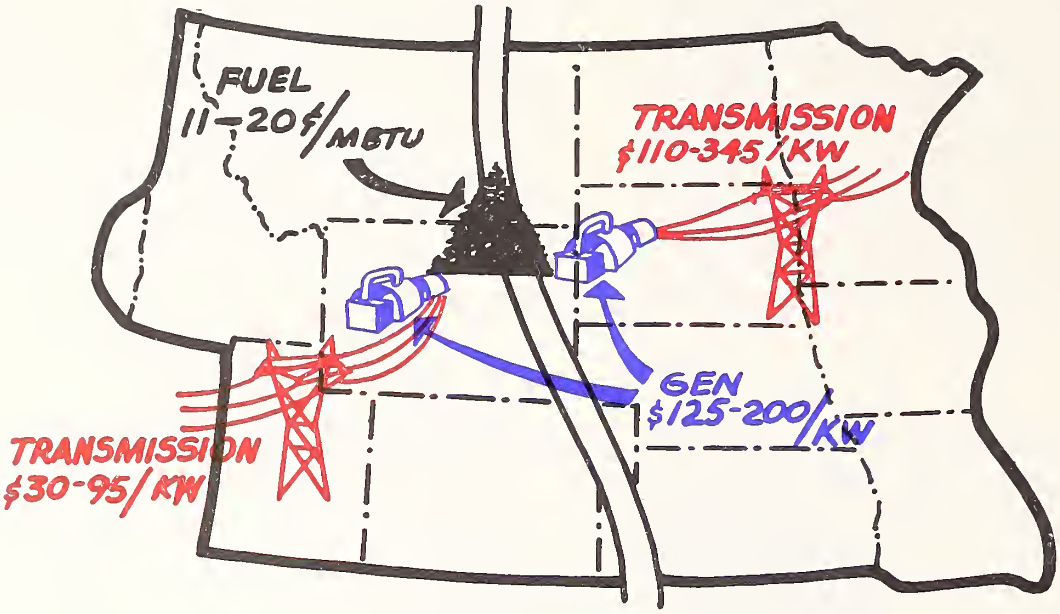
LAND RECLAMATION

II G-2 LAND RECLAMATION

The Land Reclamation Task Force has estimated the costs of modern methods of reclaiming strip-mined areas. They have examined applicable laws and practices throughout the West and generated several tables and procedures useful in estimating quantities of earth that must be relocated in strip mining. The economics of land reclamation favor the NCPS objective of minimizing the environmental impact of strip mining.

The semiarid conditions throughout the coal regions make reclamation rather difficult. Reclamation to date has had mixed results, with success in some areas in establishing grasses and other vegetation. Irrigation is limited to areas in which water supply is available. One mine operator has demonstrated that the soil materials in the spoils will produce an adequate cover with proper fertilization and seeding. Spoils in the mining area are generally not toxic, and mined areas are self-contained. Perhaps research into the use of some of the blow-down water charged to the NCPS plan would uncover a way to prime the growth of native vegetation which, incidentally, is not plentiful to begin with.

Most of the region's mining is remote to population centers where land values are quite low. Little earthwork has been required in the past, and spoils at one site required no dirt work because of the method of mining. Reclamation costs may vary from less than $100 to nearly $500 per acre, with the degree of leveling and pit width having an important effect on the exact cost. In any case, land reclamation is a small part of the fuel cost. For example, at $500/acre and with a coal yield of 20,000 tons per acre, land reclamation costs would be 2.5 cents per ton or .14 cent/million B.t.u. with 9,000 B.t.u./lb. coal.



ECONOMICS

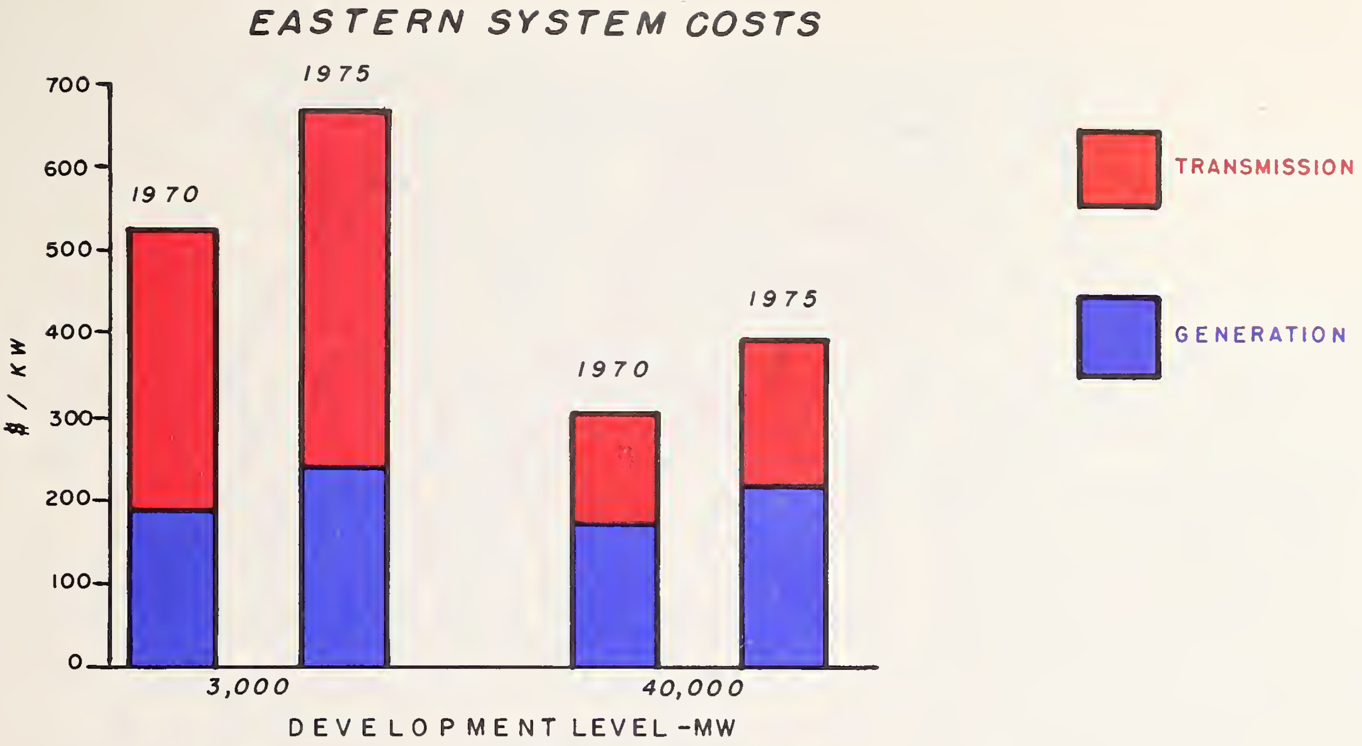
II H ECONOMICS

The Economics Committee has provided basic cost criteria for the use of the other NCPS task forces and committees. For estimating purposes 1970 costs were used, but these were also escalated to 1975 costs at 5 percent per year. The Committee also provided an overall cost analysis for the entire plan which includes the cost of taxes and interest during the construction period.

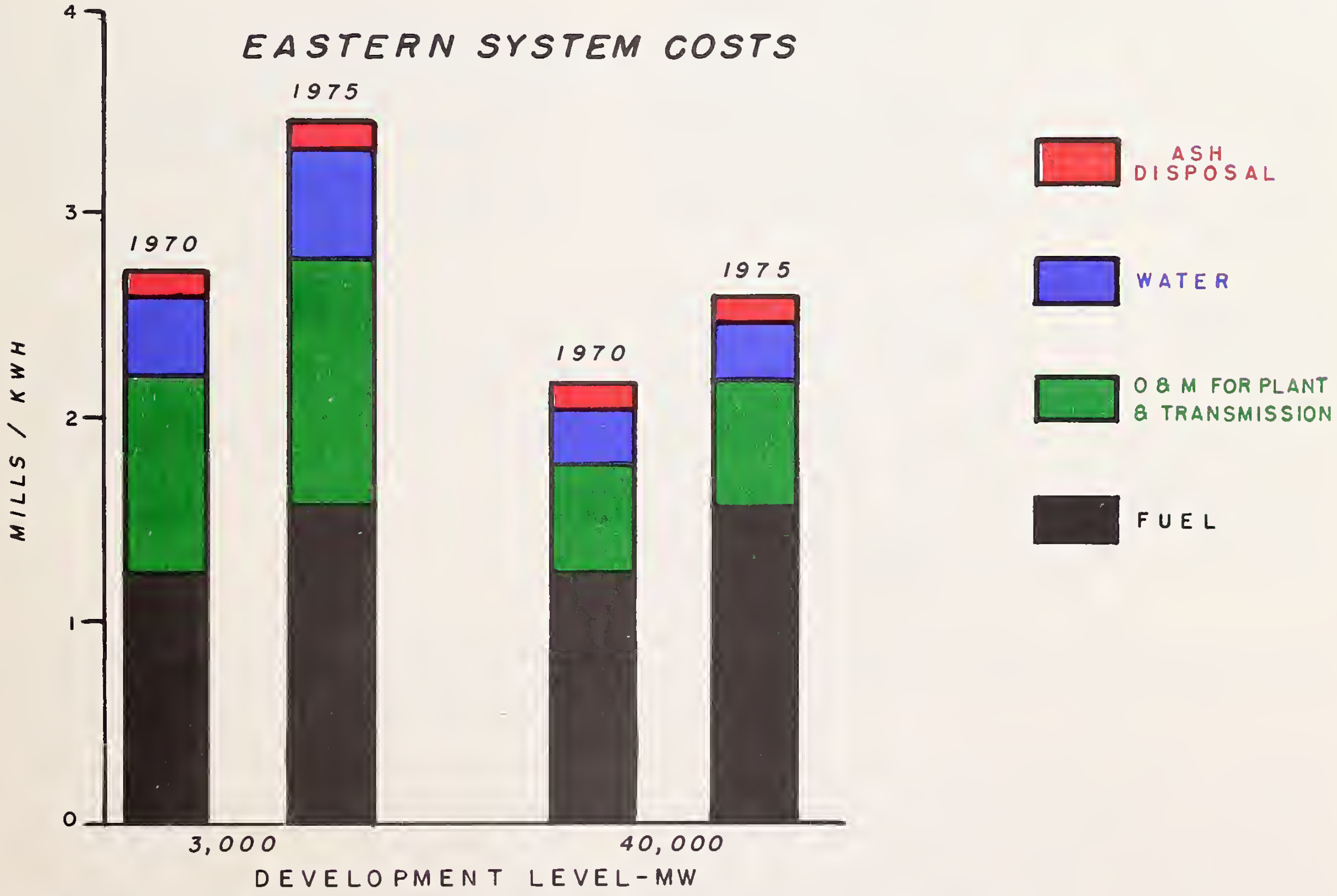
Figures II H-1 and II H-2 show the capital investment and the annual energy costs respectively for two sizes of development at the 3,000- and 40,000-mw levels. Component costs comprising the total are also shown on these figures.

Savings possible with the large-scale generation and transmission require participation of a number of power users. In order to make the generation savings available to all participants and to provide some further incentive for the users distant from the coalfields, the Committee developed a transmission sharing plan for the eastern system. In this plan three-fourths of the transmission cost is shared on a kw-mile basis and the remaining one-fourth strictly on proportion of kw participation in the generating complex. Application of this scheme requires a system with the power distribution at specified delivery points. Examples for the largest and smallest developments are fully developed in the report of the Committee in Chapter III. There are other methods of allocating transmission costs such as an average rate which could be used, and sufficient data is given in the appendix to evaluate individual costs based on these as well as other alternates. In Phase II, the entities desiring actual participation in the development should determine a mutually agreeable method of allocating transmission costs.

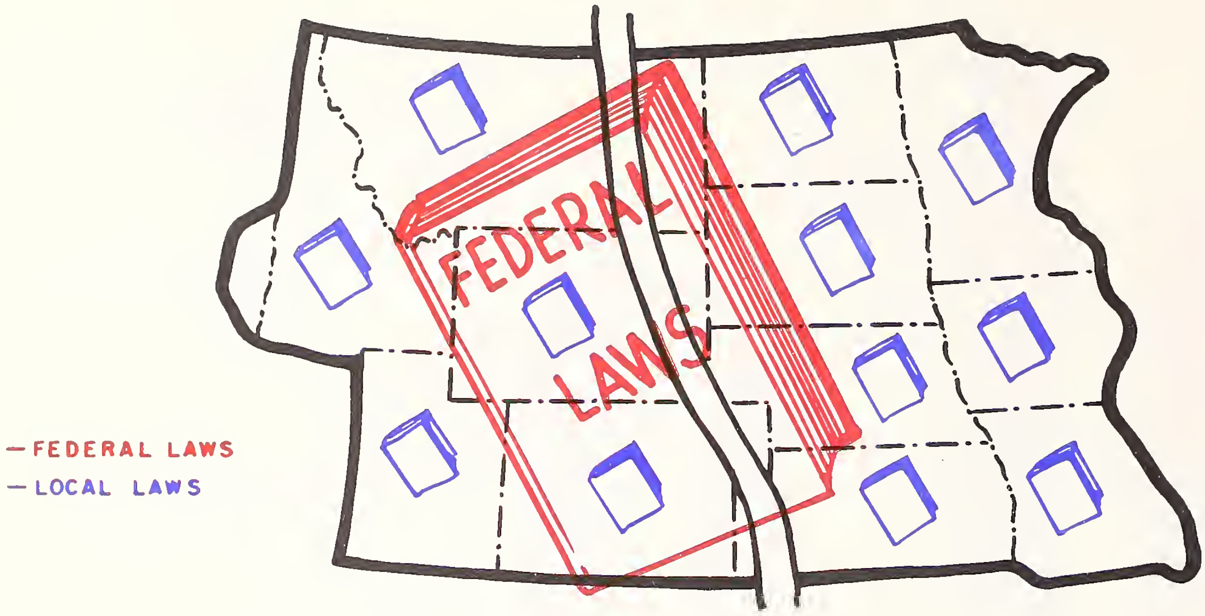
To insure maximum utility of the Study, the Economics Committee has established costs and developed curves that allow a participant to estimate his cost per kwh for annual revenue requirements different than the 11.3 percent value developed for a composite public-private venture. These curves and the other information provided in Chapter III should give enough cost information to allow participants to meaningfully compare this plan with their alternatives.



TOTAL CAPITAL INVESTMENT VS DEVELOPMENT
Figure II H-1



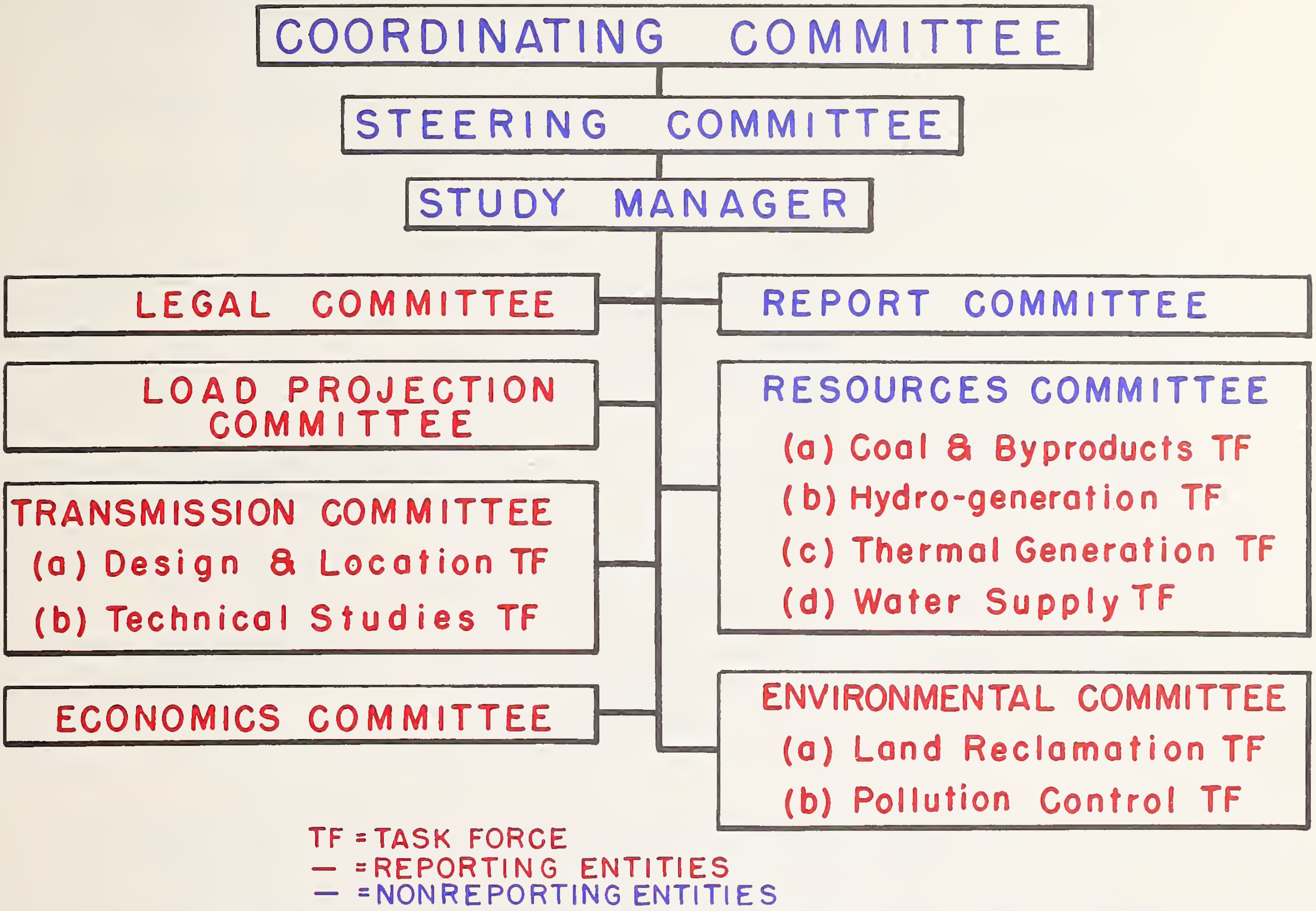
ANNUAL ENERGY PRODUCTION COSTS VS DEVELOPMENT
Figure II H-2



LEGAL

III LEGAL

The Legal Committee was formed to investigate the legal aspects of proposed NCPS developments and has been available to answer legal questions in Phase I. However, it was agreed that the Legal Committee's detailed work can begin only after a particular development is proposed by the planners. This would logically take place in Phase II, when details such as the actual participants, plant location, ownership of resources, and transmission routings are specified. The Committee has said it knows of no overriding obstacles to the development of large generating complexes and transmission systems of the type proposed in the NCPS plans.



COMMITTEE AND TASK FORCE REPORTS

III COMMITTEE AND TASK FORCE REPORTS

The work on the North Central Power Study was a team effort among the many committees and task forces that were formed. This section, which was written by the individual working groups, gives additional information supplementing the data given in Chapter II.

III A LOAD

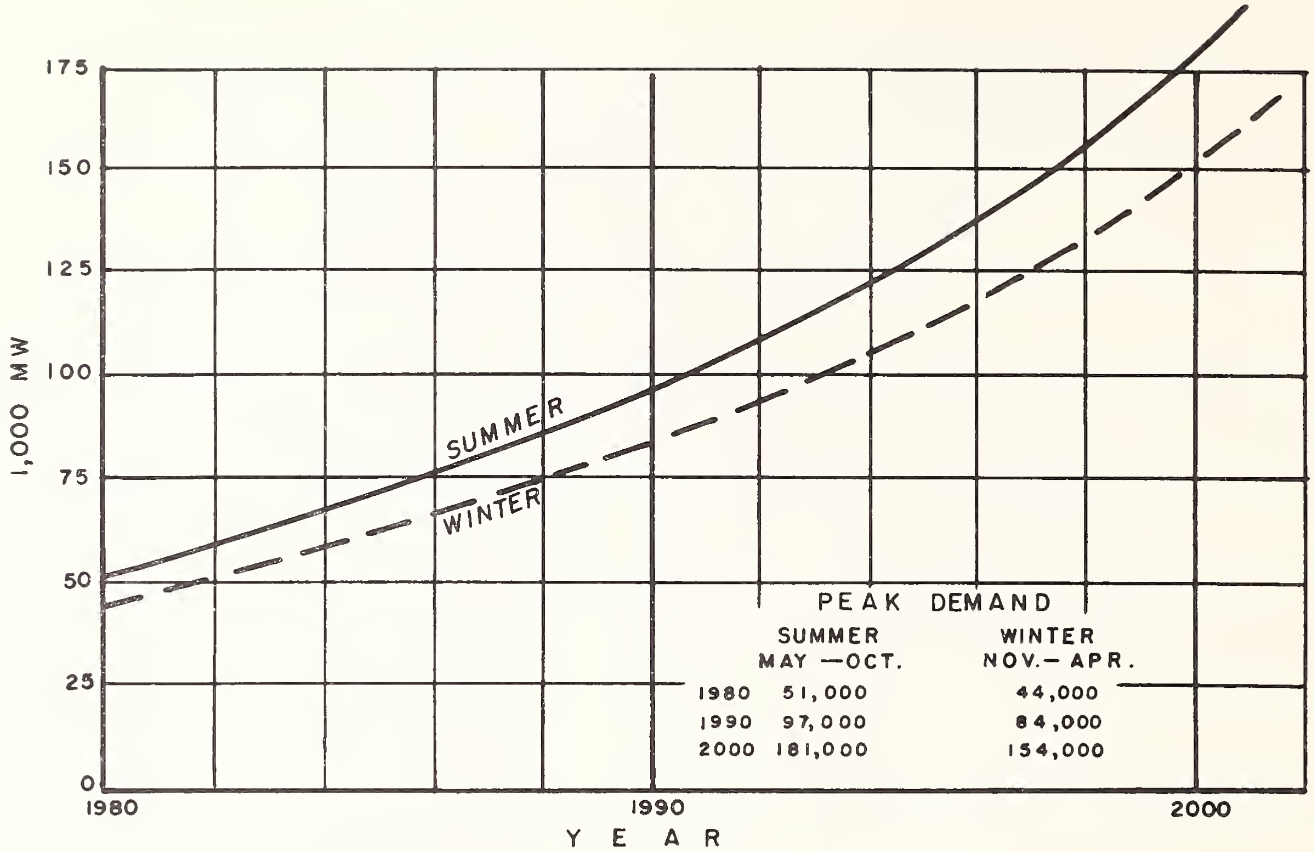
CONCLUSIONS

The North Central Power Study area noncoincidental summer peakload demand is estimated to be about 51,000 mw in 1980, and increases to about 181,000 mw in 2000, an increase of 130,000 mw over the 20-year period for an average annual growth rate of about 6.5 percent. The study area noncoincidental winter peakload demand is estimated to be about 44,000 mw in the 1980-81 winter, and increases to about 154,000 mw in the 2000-01 winter, an increase of 110,000 mw over the 20-year period for an average annual growth rate of about 6.4 percent. Figure III A-1 shows the total study area estimated load requirements and Tables III A-1 and III A-2 show the load requirements and load growth by utilities for the study period.

The 1964 National Power Survey estimated the 1980 noncoincidental peak demand of the contiguous United States at about 494,000 mw. The North Central Power Study area noncoincidental summer peak requirement for 1980 as estimated is about 10 percent of the total U.S. requirement. Estimates indicate that the North Central Power Study area as compared to the contiguous United States has roughly 34 percent of the geographic area, and by 1980 it is estimated that the North Central area population may be about 10 percent of the population of the contiguous United States.

The North Central Power Study area was divided into two systems, one East and the other West of the East-West transmission ties.

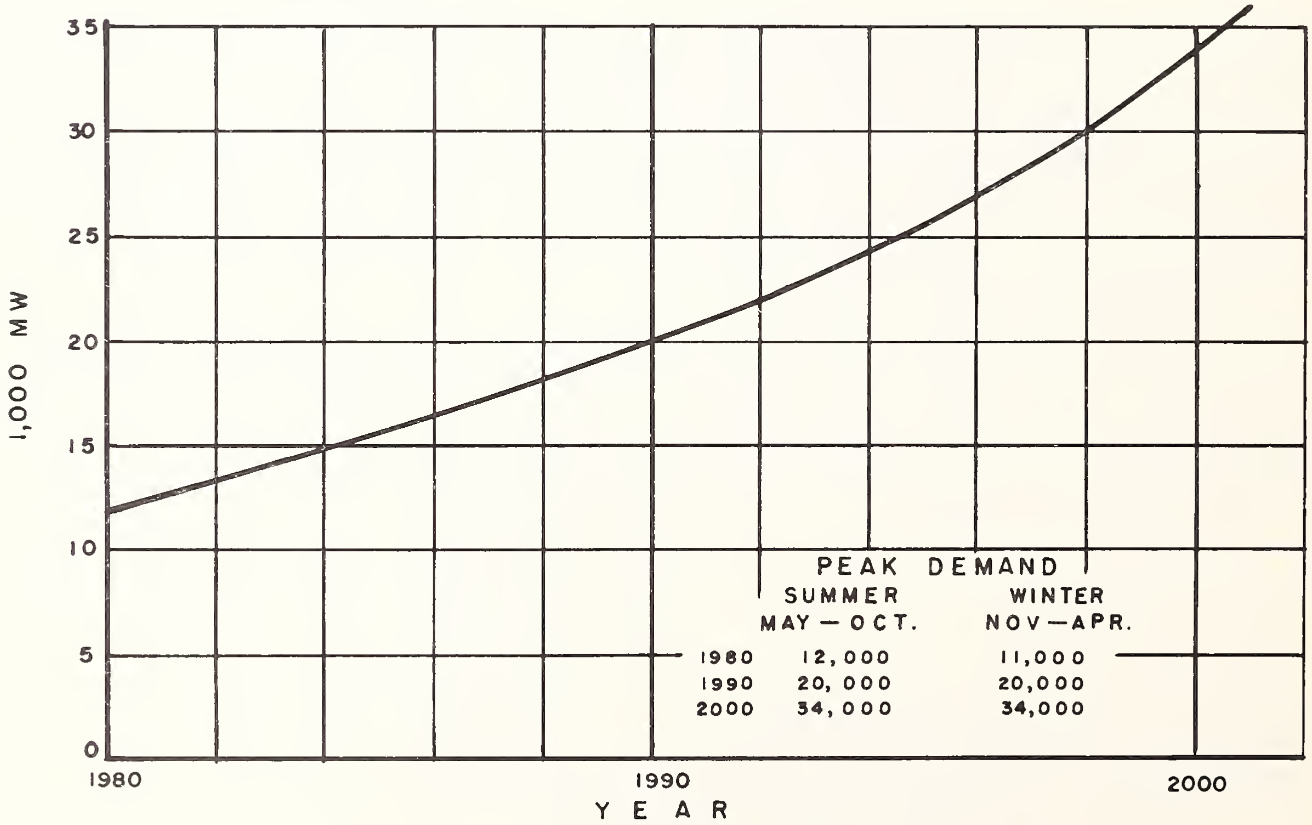
The East System noncoincidental summer peakload demand is estimated to be about 39,000 mw in 1980 and increases to about 147,000 mw in 2000, an increase of 108,000 mw over the 20-year period for an average annual growth rate of about 6.9 percent. The east System noncoincidental winter peakload demand is estimated to be about 33,000 mw in 1980 and increases to about 120,000 mw in 2000, an increase of 87,000 mw over the 20-year period for an average annual growth rate of about 6.7



PEAK DEMAND

	SUMMER MAY —OCT.	WINTER NOV.— APR.
1980	51,000	44,000
1990	97,000	84,000
2000	181,000	154,000

TOTAL STUDY AREA



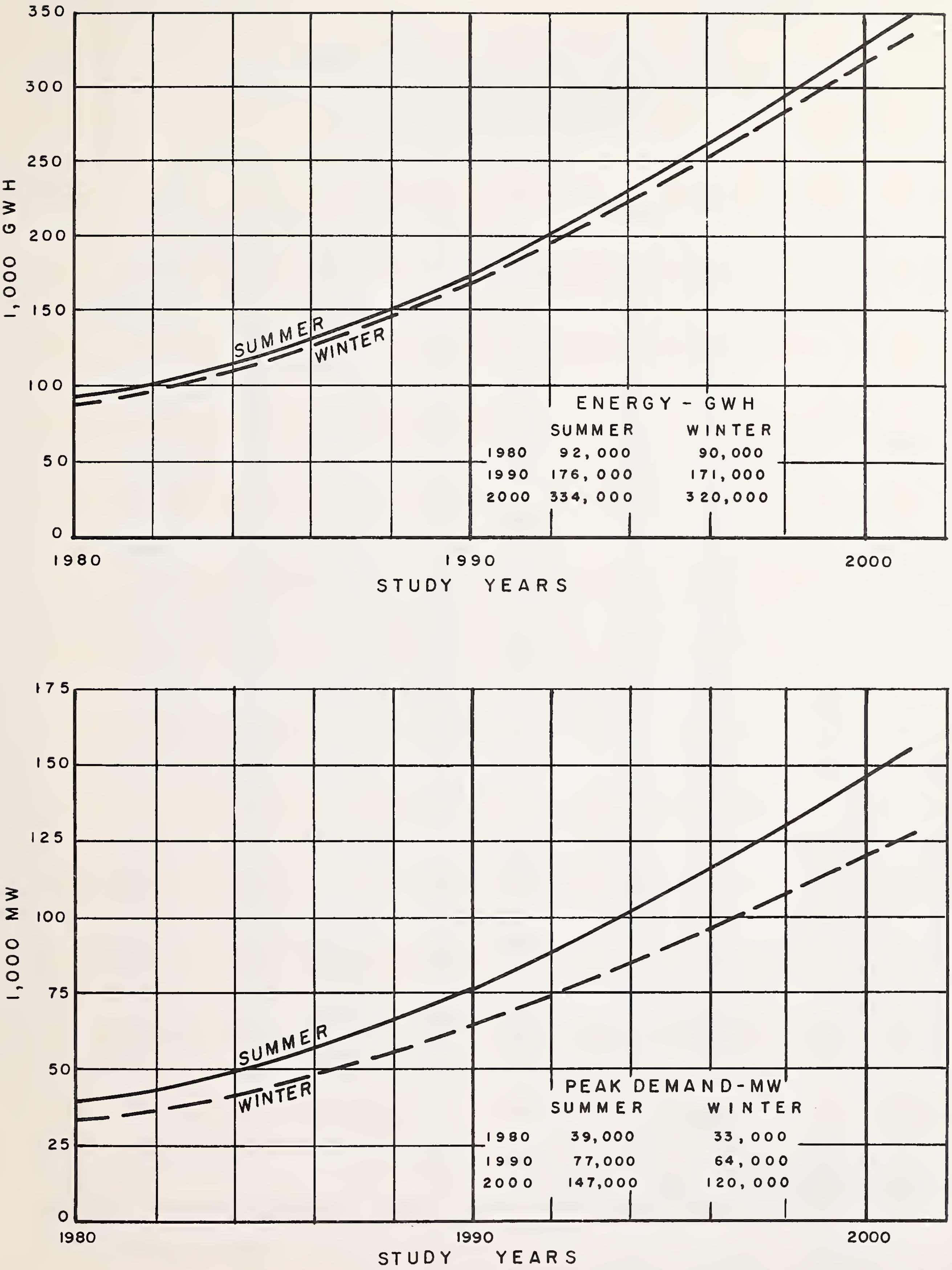
PEAK DEMAND

	SUMMER MAY — OCT.	WINTER NOV—APR.
1980	12,000	11,000
1990	20, 000	20,000
2000	34, 000	34,000

WEST SYSTEM AREA

NORTH CENTRAL POWER STUDY
LOAD PROJECTION

Figure III A-1



NORTH CENTRAL POWER STUDY
EAST SYSTEM AREA LOAD PROJECTION
Figure III A-2

Table III A-1

NORTH CENTRAL POWER STUDY AREA LOADS

MW and Avg. Annual Growth
(Summer Peak Demand)

	1980	%	1985	%	1990	%	2000	1980-2000 % Growth
Assoc. E Coop.	1,856	10.0	2,986	10.0	4,814	10.0	12,486	10.0
BEP Coop. (West)	794	5.5	1,038	5.5	1,356	5.1	2,226	5.3
BEP Coop. (East)	1,171	5.3	1,517	5.3	1,965	5.4	3,321	5.3
BHPL	168	5.1	215	5.7	284	5.2	473	5.3
DPC	479	7.0	671	6.9	933	6.9	1,811	6.9
IIGE	1,257	7.2	1,780	7.2	2,519	6.4	4,700	6.8
IPL	1,319	6.0	1,766	6.0	2,363	6.0	4,231	6.0
ISP	808	6.0	1,080	5.0	1,378	5.0	2,245	5.2
IELP-CIPCO	1,318	8.0	1,940	8.0	2,853	7.9	6,111	8.0
IPS	876	6.9	1,222	8.0	1,800	7.5	3,700	7.5
ISU	527	8.0	774	7.0	1,086	7.0	2,130	7.2
KCPL	2,816	6.5	3,858	6.5	5,285	6.5	9,922	6.5
MDU	270	4.3	334	4.4	415	4.7	654	4.5
MPL	1,152	5.0	1,467	5.1	1,878	2.9	2,506	4.0
Municipals 1/	2,206	5.5	2,885	5.0	3,684	5.0	6,000	5.1
NWPS	272	5.9	362	5.9	481	5.9	855	5.9
NPPD	2,186	5.9	2,915	5.3	3,765	5.0	6,132	5.3
NSP	6,920	7.0	9,706	7.0	13,613	6.6	25,842	6.8
OPPD	1,669	4.5	2,082	3.9	2,528	3.3	3,503	3.8
OTP	332	6.0	444	6.0	594	6.0	1,065	6.0
UE 2/	9,129	7.4	13,046	7.4	18,644	7.4	38,077	7.4
UPA RCPA	348	11.9	610	7.1	860	5.9	1,530	7.7
NMPA	128	7.1	180	6.1	242	5.0	394	5.8
USBR								
Region 4 (West)	1,159	1.0	1,221	1.3	1,304	1.8	1,562	1.5
Region 6	2,435	6.2	3,295	6.3	4,476	6.9	8,704	6.6
Region 7 (East)	135	6.0	181	5.9	241	3.7	348	4.8
Region 7 (West)	395	10.8	659	9.7	1,046	10.1	2,748	10.2
Colo-Ute (West)	273	9.0	420	9.5	662	9.1	1,585	9.2
IPC (West)	782	3.4	924	3.9	1,119	4.6	1,747	4.1
MPC (West)	1,083	5.1	1,388	5.1	1,784	5.2	2,967	5.2
PSC Colo (West)	3,244	7.6	4,690	7.8	6,813	4.9	10,976	6.3
PPL (Wyo.) (West)	670	7.0	940	5.7	1,240	5.1	2,040	5.7
UPL (West)	2,780	5.2	3,590	5.5	4,690	5.6	8,110	5.5
GRAND TOTAL	50,957	6.6	70,186	6.6	96,715	6.4	180,701	6.5
Total East System	39,777	6.8	55,316	6.8	76,701	6.7	146,740	6.7
Load Growth 1980-2000 106,963 MW								
One-Third 1980-2000 Load Growth 35,654 MW, Rounded to 40,000 MW for 1978-2000								
Total West System	11,180	5.9	14,870	6.1	20,014	5.4	33,961	5.7
Load Growth 1980-2000 22,781 MW								
One-Third 1980-2000 Load Growth 7,594 MW, Rounded to 10,000 MW for 1978-2000								

1/ Municipal loads for most of the area are included in Utility and Federal loads. Municipal loads in the extreme east and southeast part of the Study area are shown on this line.

2/ Later information indicates annual load growth of 6.25%.

Table III A-2

NORTH CENTRAL POWER STUDY AREA LOADS

MW and Avg. Annual Growth
(Winter Peak Demand)

	1980-81	%	1985-86	%	1990-91	%	2000-01	1980-2000 % Growth
Assoc. E	1,893	10.0	3,046	10.0	4,910	10.0	12,736	10.0
BEP Coop. (West)	728	5.8	967	5.8	1,280	5.1	2,102	5.8
BEP Coop. (East)	1,447	5.8	1,919	5.8	2,543	5.8	4,465	5.8
BHPL	179	5.1	229	5.8	303	5.2	502	5.3
DPC	668	6.8	930	6.8	1,295	6.9	2,513	6.9
IIGE	1,016	7.0	1,424	7.2	2,015	6.4	3,760	6.8
IPL	966	6.0	1,292	6.0	1,730	6.0	3,097	6.0
ISP	715	6.0	956	5.0	1,220	5.0	1,987	5.2
IELP-CIPCO	1,160	6.9	1,619	6.9	2,261	6.9	4,411	6.9
IPS	697	5.8	924	7.6	1,330	6.5	2,500	6.6
ISU	387	7.0	543	7.9	796	8.0	1,720	7.7
KCPL	1,830	6.5	2,508	6.5	3,435	6.5	6,449	6.5
MDU	282	2.8	324	4.4	402	4.6	633	4.1
MPL	1,300	5.2	1,677	5.3	2,171	3.0	2,912	4.1
Municipals 1/	2,206	5.5	2,885	5.0	3,684	5.0	6,000	5.1
NWPS	190	6.0	254	5.9	339	6.0	605	6.0
NPPD	1,473	5.7	1,939	5.1	2,481	4.8	3,975	5.1
NSP	6,095	7.0	8,548	7.0	11,989	6.0	21,470	6.5
OPPD	1,053	4.8	1,334	4.4	1,653	4.0	2,452	4.3
OTP	435	6.0	582	6.0	778	6.0	1,393	6.0
UE 2/	5,906	7.4	8,441	7.4	12,063	7.4	24,636	7.4
UPA RCPA	371	10.3	605	7.2	855	5.9	1,520	7.3
NMPA	166	8.5	249	6.0	334	5.0	545	6.1
USBR								
Region 4 (West)	1,024	2.4	1,100	1.8	1,202	2.4	1,523	2.0
Region 6	2,591	6.5	3,543	6.6	4,874	6.7	9,340	6.6
Region 7 (East)	125	6.3	170	6.0	228	3.8	332	5.0
Region 7 (West)	435	9.9	698	9.0	1,075	9.2	2,588	9.3
Colo-Ute (West)	328	9.0	504	9.4	788	9.2	1,900	9.2
IPC (West)	630	2.7	718	3.2	839	3.9	1,225	3.4
MPC (West)	1,313	5.2	1,694	5.3	2,192	5.3	3,688	5.3
PCS Colo (West)	3,396	7.1	4,794	7.2	6,798	4.9	10,949	6.0
PPL (Wyo.) (West)	780	7.1	1,100	5.5	1,440	5.0	2,340	5.6
UPL (West)	2,540	5.2	3,290	5.4	4,270	5.6	7,360	5.5
GRAND TOTAL	44,325	6.5	60,806	6.6	83,573	6.3	153,628	6.4
Total East System	33,151	6.7	45,931	6.8	63,689	6.5	119,953	6.6
Total West System	11,174	5.9	14,875	6.0	19,884	5.4	33,675	5.7

1/ Municipal loads for most of the area are included in Utility and Federal loads. Municipal loads in the extreme east and southeast part of the Study area are shown on this line.

2/ Later information indicates annual load growth of 9.6%.

percent. Estimated summer energy requirements for the East System increase from about 92,000 gwh in 1980 to about 334,000 gwh in 2000, for an average annual energy growth rate of 6.7 percent. Winter energy requirements increase from about 90,000 gwh in 1980 to about 320,000 gwh in 2000, for an average annual energy growth rate of 6.6 percent. See Figure III A-2 for the East System load projection. Seasonal load factors for the East System in 1980 are estimated to be about 52 percent for summer and about 62 percent for the winter. The summer and winter seasons include the months May-October and November-April, respectively. Analysis of the East System loads with respect to type of service indicated that about 70 percent is investor owned, 20 percent cooperatives, and 10 percent municipal and miscellaneous.

The West System noncoincidental summer peakload demand is estimated to be about 12,000 mw in 1980 and increases to about 34,000 mw in 2000, an increase of 22,000 mw over the 20-year period. System noncoincidental winter peakload demand is estimated to be about 11,000 mw in 1980 and increases to 34,000 mw in 2000. See Figure III A-1 for the West System load projection.

The load to be served from the NCPS development was restricted by study criteria to one-third of the load growth in order to obtain a suitable balance between local generation at the load centers and the remote generation in the coalfields. For the Eastern System one-third the total load growth between 1978 and 2000 is approximately 40,000 mw and for the Western System about 10,000 mw. Studies were run at 3,000, 10,000, 20,000, and 40,000-mw levels for the East and 1,000, 3,000, and 10,000 for the West.

SCOPE

The North Central Power Study area includes the States of Idaho, Montana, Wyoming, North and South Dakota, Nebraska, Minnesota, Iowa, and parts of Oregon, Colorado, Utah, Kansas, Missouri, Illinois, and Wisconsin. Study area estimated loads are for all utilities whether represented directly on the Coordinating Committee or not.

Electric power load estimates by seasons for the years 1980, 1985, 1990, and 2000 were obtained from each North Central Power Study Coordinating Committee member.

STUDY PROCEDURES

Instead of using load estimates from existing reports, each member of the Coordinating Committee was requested to prepare estimates of his system seasonal demand and energy requirements by load points for the years 1980, 1985, 1990, and 2000, indicating for his system such items as transmission losses, reserve generating capacity obligation, net generating capacity owned or planned, planned interchange with other power systems, and amounts of power which he would consider purchasing from the proposed North Central power source. No attempt was made to estimate the power requirements for the mining and processing of fuel for the proposed North Central power production facilities.

RESULTS

The North Central Power Study load data as obtained from the Coordinating Committee members were assembled by Federal Power Commission Power Supply Areas in order to determine if the study load estimates were within estimating error range with the load data assembled by the Federal Power Commission. For power supply areas wholly within the boundaries of the study area, the North Central Power Study load estimates for 1980 compared very favorably with the Federal Power Commission estimates for the same year.

III B-1 COAL

The Task Force on Coal and Coal Byproducts of the Resources Committee of the North Central Power Study has developed a list of locations having strip coal reserves capable of supporting 1,000 mw or larger coal burning thermal generating plants at each site.

The basis for establishing the necessary reserves per 1,000 mw were as follows:

1. Assume 9,400 B.t.u. per net kwh.
2. Assume plant capacity factor of 85 percent.
3. Assume 35-year life at base load.

The Task Force recognizes that units do not normally operate as base load plants for this length of time. However, there exists a strong possibility it may be desirable for the new mine-mouth plants to serve as base load units for the longer period.

Limits used to define a stripable deposit in the west are: (1) minimum coalbed thickness of 5 feet unless a thinner coalbed, occuring as a rider seam, would be recovered during the mining operation; (2) overburden to coal ratio of less than 10 cubic yards of overburden to 1 ton of coal; and (3) total overburden thickness of less than 120 feet except where reserves occur in multiple beds or a thick single bed under overburden locally as much as 200 to 260 feet thick. Table III B-1.1 provides details on reserves, quality, seam thickness and overburden at the various sites. The exception to these overburden thickness criteria is the Sorenson deposit in Lincoln County, Wyoming. There, the Kemmerer Coal Company has started an open pit that would be 1 mile square with a high wall of 1,100 feet. Several thick coalbeds will be recovered at the favorable stripping ratio of 7 to 1. Maximum overburden and total tons for each deposit estimated by these criteria are shown in the appendix on the line with the deposit name.

Table III B-1.1

STRIPPABLE COAL SITES FOR 1,000 OR MORE BASE LOAD MINE MOUTH GENERATING PLANTS

DEPOSIT CHARACTERISTICS

Site Identification Number	Overburden in feet		Coal thickness in feet - range	Reserves-in millions of tons	Heat Content B.t.u./lb.	Sulfur Content in percent
	Min.	Max.				
1	10	130	10 - 40	1,372	5,800-6,400	0.6-1.6
2	15	100	5 - 22	877	6,750-7,050	0.5-0.9
3	20	100	5 - 18	800	6,280	1.0
4	15	90	5 - 22	253	7,000-7,050	0.9
5	10	100	5 - 10	300	6,000	1.0
6	10	200	18 - 36	1,900	7,850	0.4
7	15	120	12 - 35	2,892	8,700	0.3
8	20	120	5 - 40	1,204	6,050	0.9
9	20	150	11 - 29	1,440	9,050	0.7
10	15	120	8 - 16	1,190	7,500-7,700	0.2-1.0
11	10	200	20 - 89	1,189	9,720	0.4
12	10	150	20 - 60	1,044	8,740	0.2
13	15	120	8 - 21	1,366	7,400-7,650	0.4-0.6
14	20	100	6 - 30	1,497	8,100-8,900	0.2-0.7
15	15	120	5 - 26	737	7,550	0.2
16	15	120	10 - 43	225	6,900	0.5
17	20	100	7	246	6,600	0.4
18	20	125	5 - 8	331	6,750-6,800	0.2
19	15	120	5 - 9	561	7,150	0.9
20	10	100	5 - 9	345	7,400	0.3
21	15	125	25	600	5,830	0.4
22	20	120	58	441	7,700	0.2
23	20	120	18	200	8,850	0.6
24	15	120	20	220	8,500	0.4
25	10	150	20	206	7,650	0.2
26	20	150	5 - 18	250	8,200	1.1
27	25	200	50 - 250	2,000	7,950	0.7
28 to 37	10	200	25 - 150	19,000	8,200-8,500	0.4-0.9
38	10	120	6 - 18	733	8,000-8,700	1.8-5.4
39	20	1,600	10 - 90	1,000	10,400	0.6
40	15	120	10 - 12	716	7,800	--
41	20	200	15 - 30	250	9,700	0.8
42	20	140	10 - 50	600	5,500	--

The ground rules for the North Central Power Study requested that plant installations of 1,000, 3,000, 5,000, and 10,000 mw be considered. The Task Force agreed to consider that recoverable reserves from new strip developments would be 80 percent of the "proven" reserves. Proven reserves are defined as those reserves which have been located by either detailed or preliminary drilling operations. Table III B-1.2 shows the "proven" reserves of stripable coal of various B.t.u. contents required for the several plant sizes being considered.

Figure II E-1.1 shows the general location of the coal fields and generation support capability of the coal sites. Table III B-1.3 identifies the locations having sufficient stripable coal reserves to serve plants of the sizes requested. These locations were selected on the basis of extensive information supplied through the Bureau of Mines.

In regard to the supplying of byproducts from synthetic fuel plants using coal, the Task Force cannot predict when or where synthetic fuel plants will be erected. However, the following general statements can be made:

1. Synthetic fuel plants will be in direct competition with powerplants for the large (3,000 mw or larger capability) reserves of strippable coal.

2. The first application will probably be for the production of synthetic pipeline gas. However, it is anticipated that any such plants will probably not produce sufficient byproduct fuel to carry a 1,000 mw generating plant.

3. Synthetic liquid fuel plants of the minimum size of 100,000 barrels per day could each supply char adequate for a 1,500 mw base load powerplant.

4. Coal can be converted by several techniques to alternate fuels for powerplant use. These include solvent extraction to produce a reconstituted fuel with low ash and sulfur contents, production of synthetic liquid fuel, and production of either high or low B.t.u. gas. None of these have progressed to demonstration plant stage, and consequently no reasonable estimates of cost or reliability can be made. It is anticipated that such information will be available by 1976-1980, but the detailed study of alternate fuels was not assigned to the Task Force.

Coal prices are certain to escalate because of various factors including:

1. Labor.

2. Capital equipment.

3. Power.

4. Supplies.

5. Royalties and leases.

6. Governmental regulations on safety and environmental considerations.

7. Competitive demand for coal.

Each of these factors, and any others not presently recognized, is causing escalation in the cost of mine-mouth coal. The magnitude of each is impossible to evaluate with any precision; however, coal escalation was assumed to be 5 percent per year, the same rate used elsewhere in the study.

The estimated price of coal varies considerably across the various fields listed. It is recognized that other factors, such as location, availability of water, and environmental factors will color the cost per million B.t.u.'s at the mines.

Table III B-1.4 gives the estimated range of cost of coal from the various fields, based on 1970 costs at mine-mouth tipple excluding land reclamation costs.

Table III B-1.2

PROVEN RESERVES VERSUS B.T.U. CONTENT

	Requires "Proven" Reserves, Millions of Tons			
B.t.u./lb. coal	1,000 mw	3,000 mw	5,000 mw	10,000 mw
6,000	256	768	1,280	2,560
7,000	219	657	1,095	2,190
8,000	191	573	955	1,910
9,000	170	510	850	1,700
10,000	153	459	765	1,530
11,000	140	420	700	1,400

Table III B-1.3

STRIPPABLE COAL SITES FOR 1,000 MW OR MORE BASE LOAD MINE-MOUTH GENERATING PLANTS 1/

Site Identification Number	State	Plant Size MW	Deposit Name	Location
1	North Dakota	5,000	Slope & Bowman Counties	Bowman, N.D.
2	" "	5,000	Knife River	Beulah, N.D.
3	" "	3,000	Heart River	Dickinson, N.D.
4	" "	1,000	Center	Center, N.D.
5	South Dakota	1,000	Cave Hills	Ludlow, S.D.
6	Montana 2/	10,000	Pumpkin Creek	20 m. N.W. Broadus, Mont.
7	"	10,000	Hanging Woman Creek	10 m. S. Birney, Mont.
8	"	5,000	Beach-Wibaux	Wibaux, Mont.
9	"	5,000	Colstrip	Colstrip, Mont.
10	"	5,000	Foster Creek	Volborg, Mont.
11	"	5,000	Decker	Decker, Mont.
12	"	5,000	Otter Creek	10 m. S.E. Ashland, Mont.
13	"	5,000	"S" Bed	10 m. N.W. Brockway, Mont.
14	"	5,000	Moorhead	Moorhead, Mont.
15	"	3,000	Broadus	Broadus, Mont.
16	"	1,000	North Fork of 13 Mile Cr.	25 m. N.W. Savage, Mont.
17	"	1,000	Reserve	Reserve, Mont.
18	"	1,000	Fort Kipp	Fort Kipp, Mont.
19	"	1,000	Lane	Richey, Mont.
20	"	1,000	Carroll	Paxton, Mont.
21	"	1,000	Coalridge	Coalridge, Mont.
22	"	1,000	Poker Jim - Lookout	Birney, Mont.
23	"	1,000	Birney	Birney, Mont.
24	"	1,000	Kirby	Kirby, Mont.
25	"	1,000	Sonnette	Sonnette, Mont.
26	"	1,000	Sweeney Creek	10 m. N.W. Brandenberg, Mont.
27	Wyoming	10,000	Lake De Smet	10 m. N. Buffalo, Wyo.
28 thru 37	"	10,000 ea. (100,000 mw total)	Gillette	15 miles N. of Gillette to Antelope Creek (55 miles S. of Gillette, Wyoming)
38	"	5,000	Red Desert-Cherokee	N. of Wamsutter, Wyo.
39	"	5,000	Adaville	6 m. W. of Kemmerer, Wyo.
40	"	3,000	Spotted Horse	Spotted Horse
41	"	1,000	Jim Bridger	25 m. N.E. Rock Springs, Wyo.
42	Colorado 3/	1,000	Denver Basin	Watkins, Colorado
	Kansas, Iowa,		No sites	
	Nebraska, Missouri,		" "	
	Minnesota		" "	

1/ Based on: (1) 80% recovery, (2) 9,400 Heat Rate, (3) 35-year life at 85% plant capacity factor.

2/ In addition, Montana has other probable, but not yet identifiable, sites on Northern Cheyenne and Crow Indian Reservations.

3/ The Colorado site because of the very low B.t.u., high ash coal is only marginally attractive.

Table III B-1.4

COAL COST AT MINE MOUTH

Field Identification Nos.	1970 Mine Mouth Cost ¢/Million B.t.u.'s
1-3	12.5-14
4-5	13 - 15
6-15	11 - 13
16-27	12 - 14
28-37	11 - 12
38-41	15 - 18
42	15 - 20

III B-2 THERMAL GENERATION

The Thermal Generation Task Force developed cost estimates for construction and operation of two 500 mw and two 1,000 mw coal-fired mine-mouth units for 1970 in the Montana-Wyoming-North Dakota-South Dakota areas. These costs were escalated at 5 percent annually to 1975. The study is based on the use of induced draft wet cooling towers, but estimates are also supplied on dry cooling costs for use where the water supply might be limited.

The assumptions under which the cost estimates in the capital cost and operating cost Tables III B-2.1 and -2.2 apply are:

1. Semienclosed plants with no benefit assumed for more than two units at a site.

2. These items are excluded from the cost estimates:

   a. Step-up transformers.

   b. Land costs for recreational purposes.

   c. Interest during construction.

   d. Ad valorem taxes during construction.

   e. Administrative and General charges on Operation and Maintenance.

   f. Maintenance of scrubbing equipment.

   g. The additional data required to make use of these capital and operating costs have been supplied by the Economics, Coal, Water and Transmission Committees.

3. A plant factor of 85 percent is assumed.

4. Low sulfur subbituminous coal is assumed in the base costs.

5. Cost data for precipitators with 99.5 percent efficiency and cooling towers are identified for the convenience of participants who desire to make additional analysis.

III B-3 HYDRO

CONCLUSIONS

The Hydrogeneration Task Force investigated about 30 potential conventional and pumped-storage hydropeaking sites in the Rocky Mountain and Missouri River main stem regions of the North Central Power Study area. Initially the assignment of the Task Force was to investigate all the potential hydropeaking sites in the NCPS area, but early in the study the Steering Committee directed that the potential sites near the load centers in the NCPS area should be considered in the alternative plans of the participants. Tables III B-3.1, -3.2, and -3.3 identify the thirty potential hydropeaking plants investigated. These tables show the location, type, capacity rating, number of units, peaking and pumping hours for pumped-storage plants, the estimated construction and annual O&M costs based on 1970 cost indices. Costs are also shown escalated to estimated 1975 levels.

The Steering Committee established additional limits on the Task Force as the study progressed. These limits were that 3,000 mw of hydropeaking should be developed concurrently with the eastern base load thermal system of 40,000 mw; due to the load characteristics of the area, 8 hours of peaking should be planned. These limits resulted in the selection of the 1,760-mw Cutler Park-Rockwood and 1,240-mw Sheep Mountain pumped-storage sites in Wyoming.

STUDY ASSUMPTIONS AND QUALIFICATIONS

The study assumptions and qualifications used by the Task Force are as follows:

1. Minimum capacity of peaking plant to be considered would be 100 mw.

2. Steering Committee restricted the study area to be investigated to the main stem of the Missouri River and Rocky Mountain regions of the NCPS area.

3. A minimum daily generation capability of 8 hours was established by the Steering Committee. This requirement was selected because the area hourly load curve shows a pronounced flat top with the load near maximum for a prolonged period.

Table III B-2.1

THERMAL GENERATION CAPITAL COSTS

Capital Costs (Not including IDC or ad valorem taxes during construction)

		Unit Size MW	1970	1975
1.	Generation Capital Costs in $/net kw	2 - 500	$158.00	$202.00
	Generation Capital Costs in $/net kw	2 - 1,000	124.00	158.00
2.	The generation costs above include these amounts in $/net kw for:			
	Precipitator	2 - 500	8.50	11.00
	Induced draft wet cooling tower	2 - 500	8.50	11.00
	Precipitator	2 - 1,000	7.00	9.00
	Induced draft wet cooling tower	2 - 1,000	7.00	9.00
3.	For Dry Cooling substitute these capital costs for the above wet cooling tower costs $/net kw	2 - 500	23.00	29.00
	For Dry Cooling substitute these capital costs for the above wet cooling tower costs $/net kw	2 - 1,000	21.00	27.00
4.	Land Capital Cost in $/Megawatt capacity	--	50.00/MW	65.00/MW

Annual Percent of Total Capital Expenditures During Construction of One Unit

Construction Years	1st	2nd	3rd	4th
% of total cost	10%	30%	50%	10%

Unit Availability

Mature units (after 3 years) are estimated to have availability annually as follows:

Unit Size	Maintenance Outage	Forced Outage	Total Outage	Plant Availability
500 MW	8% (4 weeks)	5%	13%	87%
1,000 MW	8% (4 weeks)	7%	15%	85%

Table III B-2.2

THERMAL GENERATION OPERATING COSTS

Operating Costs (.85 plant factor and 5% annual escalation to 1975)

	Unit Size MW	1970	1975
1. Operation and Maintenance (not including Administration and General Charges)			
Using Wet Cooling	2 - 500	.45 mill/kwh	.57 mill/kwh
Using Wet Cooling	2 - 500	$3,900/MW year	$5,000/MW year
Using Wet Cooling	2 - 1,000	.25 mill/kwh	.32 mill/kwh
Using Wet Cooling	2 - 1,000	$2,200/MW year	$2,800/MW year
With Dry Cooling add these O&M amounts to the wet cooling O&M costs:	2 - 500 MW	.053 mill/kwh $460/MW year	.067 mill/kwh $590/MW year
With Dry Cooling add these O&M amounts to the wet cooling O&M costs:	2 - 1,000 MW	.031 mill/kwh $270/MW year	.039 mill/kwh $340/MW year
2. Ash Disposal Costs			
Based on 10% ash in mills/kwh	either size	.10	.13
Based on 20% ash in mills/kwh	either size	.20	.26
3. Land Reclamation (averaged estimate) Cost is expressed in ¢/ton of coal mined		2.5¢/ton	3.2¢/ton
4. Water Consumption (with wet cooling) 17,000 acre-feet per 1,000 MW at .85 plant factor. Costs per acre foot are shown in the Water Supply Task Force Report	either size		

5. Net Heat Rate of Units with Wet Cooling, 500 MW, 9,500 B.t.u./kwh
Net Heat Rate of Units with Wet Cooling, 1,000 MW, 9,100 B.t.u./kwh
Net Heat Rate of Units with Dry Cooling, 500 MW, 10,400 B.t.u./kwh
Net Heat Rate of Units with Dry Cooling, 1,000 MW, 10,000 B.t.u./kwh

6. Coal Costs (See the Coal Task Force Report for heat content and ¢/million B.t.u., at the mine. For handling of coal from mine to plant, escalate the cost of coal by 3% for 1970 and 4% for 1975.

7. Coal Quantity Calculation
Use curves in the Thermal Generation Task Force appendix or these formulas below:
For .85 plant factor:

$$\text{Tons/MW/year} = \frac{\text{Net heat rate in B.t.u. per kwh} \times 8{,}760 \times .85 \times 10^6}{\text{B.t.u. heat content per ton of coal}}$$

$$\text{Tons/Million kwh} = \frac{\text{Net heat rate in B.t.u. per kwh} \times 10^6}{\text{B.t.u. heat content per ton of coal}}$$

Table III B-3.1

POTENTIAL HYDROPEAKING

Plant Name Hydropeaking	Type Plant	Location County	Water Source River, Lake, etc.	Add. to Exist. Plant or New Plant	Installed Capacity (MW)
COLORADO					
Sweetwater	PS	Garfield	Sweetwater Creek	New	1,200
West Beaver	PS	Teller	West Beaver Creek	New	320
Hardscrabble	PS	Custer	Hardscrabble Creek	New	500
Eight Mile	PS	Fremont	Eight Mile Creek	New	500
Webster	PS	Park	South Platte River	New	160
Poudre	Conv.	Larimer	Cache la Poudre	New	250
Poudre	PS	Larimer	Cache la Poudre	New	500
Two Forks	Conv.	Jefferson	South Platte River	New	138
MONTANA					
Allenspur	Conv.	Park	Yellowstone River	New	250
Fort Benton	Conv.	Choteau	Missouri River	New	400
Fort Peck	Conv.	Valley	Missouri River	Add.	160
Cow Creek	Conv.		Missouri River	New	720
NORTH DAKOTA					
Garrison	Conv.	Mercer	Missouri River	Add.	240
SOUTH DAKOTA					
Oahe	Conv.	Stanley	Missouri River	Add.	180
Big Bend	Conv. & PB	Lyman	Missouri River	Add.	380
Fort Randall	Conv.	Charles Mix	Missouri River	Add.	240
UTAH					
Bear Mountain	PS	Uintah	Flaming Gorge Reservoir	New	2,760
Moon Lake	PS	Duchesne	Moon Lake	New	2,224
Yellowstone	PS	Duchesne	Yellowstone River	New	1,080
McDonalds	PS	Wasatch	Jardenelle Reservoir	New	5,220
Upper Stillwater	PS	Duchesne	Rock Creek	New	2,460
Hayes Reservoir	PS	Utah	Diamond Fork Creek	New	1,060
WYOMING					
Beartooth Units					177.5
a. Thief Creek	Conv.	Park	Clarks Fork River	New	125.2
b. Sunlight	Conv.	Park	Sunlight Creek	New	14.9
c. Hunter Mountain	Conv.	Park	Clarks Fork River	New	14.4
d. Bald Ridge	Conv.	Park	Clarks Fork River	New	23
Cutler Park-Rockwood	PS	Sheridan	Cutler Creek-Tongue River	New	1,760
Kortes	PS	Carbon	North Platte River	New	125
Alcova	PS	Natrona	North Platte River	New	500
Sheep Mountain (Above Buffalo Bill) 1/	PS	Park	Shoshone	New	1-5,000

1/ Potential development 1,000 to 5,000 mw. To stay within 3,000 mw hydro limit, assumed 1,240 mw development.

Table III B-3.2

POTENTIAL HYDROPEAKING

Plant Name Hydropeaking	Installed Capacity MW	No. of Units	Peaking Period Hours	Pumping Requirement			Annual Energy Millions KWH
				Period Hours	Demand MW	Energy M/KWH	
COLORADO							
Sweetwater	1,200	6	5	10	900	2,365	
West Beaver	320	2	8	12	320	840	
Hardscrabble	500	4	8	12	500	1,315	
Eight Mile	500	4	8	12	500	1,315	
Webster	160	1	8	12	160	420	
Poudre	250	4	2	-	-		186
Poudre	500	4	8	12	500	1,315	
Two Forks	138	2	5	-	-		156
MONTANA							
Allenspur	250	-	-	-	-		638
Fort Benton	400	4	-	-	-		677
Fort Peck	160	2	-				
Cow Creek	720	-	-				1,503
NORTH DAKOTA							
Garrison	240	3	-				
SOUTH DAKOTA							
Oahe	180	2	-				
Big Bend	330	6	-				
Fort Randall	240	3	-				
UTAH							
Bear Mountain	2,760	6	8	12	2,760	7,255	
Moon Lake	2,224	4	8	12	2,224	5,845	
Yellowstone	1,080	2	8	12	1,080	2,840	
McDonalds	5,220	10	8	12	5,220	13,720	
Upper Stillwater	2,460	6	8	12	2,460	6,465	
Hayes Reservoir	1,060	2	8	12	1,060	2,785	
WYOMING							
Beartooth Units	177.5						
a. Thief Creek	125.2	2	-				470
b. Sunlight	14.9	1	-				104
c. Hunter Mountain	14.4	1	-				94
d. Bald Ridge	23	1	-				146
Cutler Park-Rockwood	1,760	-	8	14	1,760	4,625	
Kortes	125	1	8	12	125	328	
Alcova	500	4	8	12	500	1,315	
Sheep Mountain (Above Buffalo Bill) 1/	1-5,000	-	8	14	1-5,000	2,630-13,140	

1/ Potential development 1,000 to 5,000 mw. To stay within 3,000 mw hydro limit, assumed 1,240 mw development.

Table III B-3.3

POTENTIAL HYDROPEAKING

	Installed Capacity (MW)	Est. Const. Cost $/KW		Est. Annual O&M Cost $/KW	
		1970	1975	1970	1975
COLORADO					
Sweetwater	1,200	138	176	1.25	1.60
West Beaver	320	140	179	1.45	1.85
Hardscrabble	500	165	211	1.35	1.72
Eight Mile	500	182	232	1.35	1.72
Webster	160	223	285	1.75	2.23
Poudre	250	253	323	1.45	1.85
Poudre	500	123	157	1.35	1.72
Two Forks	138	184	235	2.00	2.55
MONTANA					
Allenspur	250	486	620	2.11	2.69
Fort Benton	400	402	513	2.00	2.55
Fort Peck	160	330	421	1.19	1.52
Cow Creek	720	488	623	2.50	3.19
NORTH DAKOTA					
Garrison	240	330	421	1.19	1.52
SOUTH DAKOTA					
Oahe	180	330	421	1.19	1.52
Big Bend	380	330	421	1.19	1.52
Fort Randall	240	330	421	1.19	1.52
UTAH					
Bear Mountain	2,760	90	115	1.50	1.91
Moon Lake	2,224	135	172	1.50	1.91
Yellowstone	1,080	135	172	1.50	1.91
McDonalds	5,220	95	121	1.50	1.91
Upper Stillwater	2,460	120	153	1.50	1.91
Hayes Reservoir	1,060	180	230	1.50	1.91
WYOMING					
Beartooth Units	177.5	807	1,030		
a. Thief Creek	125.2	807	1,030	2.71	3.46
b. Sunlight	14.9	807	1,030	9.26	11.82
c. Hunter Mountain	14.4	807	1,030	9.26	11.82
d. Bald Ridge	23	807	1,030	7.20	9.19
Cutler Park-Rockwood	1,760	139	177	1.64	2.09
Kortes	125	175	223	2.00	2.55
Alcova	500	111	142	1.35	1.73
Sheep Mountain (Above Buffalo Bill) 1/	1-5,000	175	223	1.50	1.91

1/ Potential development 1,000 to 5,000 mw. To stay within 3,000 mw hydro limit, assumed 1,240 mw development.

4. Due to losses in pumping-generation cycle, assumed pumped-storage plants would require approximately 3 kilowatt-hours of pumping energy to provide 2 kilowatt-hours of generation.

5. Assumed annual plant factor of pumped-storage plant in the generating cycle would be 20 percent. This is based on 8 hours peaking per day for 5 days per week and down about 4 weeks per year for maintenance.

6. Estimated capital costs are based on 1970 price indices. Costs escalated to 1975 figures using escalation factor of 5 percent per year provided by Economics Committee.

RESULTS

For Phase I of the NCPS it was decided that the hydropeaking would be limited to 3,000 mw which would be considered on the East system. The most likely sites that could be integrated into the East system were the Cutler Park-Rockwood (1,760 mw) and Sheep Mountain (1,240 mw) sites.

The Corps of Engineers has potential conventional and pumped-storage sites on the main stem of the Missouri River of about 1,200 mw which were identified for this report. This main stem hydro may reduce transmission costs significantly and should be investigated further when sites and site costs are determined.

A brief description of the proposed pumped-storage sites selected for recommendation is as follows:

CUTLER PARK—ROCKWOOD SITE

This site is located on the Tongue River west of Dayton, Wyoming. The proposed development includes construction of a concrete dam on the Tongue River (Rockwood) and an earthfill dam and dike on Cutler Creek. The proposed plan of development and its estimated cost considered facilities based on the following data:

Pump Generating Plant—1,760 mw
  No. of Units—4
  Size of Units—440 mw
  Head (maximum static head on unit)—900 feet

Plant Operation
  Pumping Period—14 hours
  Peaking Period—8 hours
Estimated 1970 Cost—$139/kw
Estimated 1970 Annual O&M Cost—$1.64/kw
  (excluding cost of pumping energy)

SHEEP MOUNTAIN SITE
(above Buffalo Bill Dam)

The proposed development plan for the Sheep Mountain impoundment above the existing Buffalo Bill Reservoir near Cody, Wyoming, provides for active storage of 6,900 acre-feet of water. The structural height of the proposed dam is 355 feet with an elevation at the top of 6,785 feet. The following data were considered in deriving the estimated cost for the pumped storage development utilizing Buffalo Bill Dam and the proposed Sheep Mountain Dam:

Pump Generating Plant—1,240 mw
  No. of Units—3
  Size of Units—413 mw
  Head (maximum static head on unit)—1,510 feet
Plant Operation
  Pumping Period—14 hours
  Peaking Period—8 hours
Estimated 1970 Cost—$175/kw
Estimated 1970 Annual O&M Cost—$1.50/kw
  (excluding cost of pumping energy)

III B-4 WATER

PREFACE

The Water Supply Task Force identified the source and computed the cost of water delivered to potential coal fields which had been located by the Coal and Byproducts Task Force. The estimated costs per acre-foot of water delivered are summarized and are based on October 1970 price levels including lands, rights, facilities, and financing.

WATER RESOURCES

Water supplies which could be used, or developed and utilized, for industrial development of coal in the Gillette-Colstrip geographic area are estimated to be about 2.8 million acre-feet annually. About one million acre-feet of this amount are immediately available from the Wind-Bighorn system and another million acre-feet from Fort Peck or Garrison Reservoir. An additional 280,000 acre-feet can be developed from potential reservoirs on the Powder, Tongue, Little Bighorn and Little Missouri Rivers. It is technically feasible to import 100,000 acre-feet from the Green River. Enlargement of Buffalo Bill Reservoir would produce an additional 50,000 acre-feet. Surplus flows from Yellowstone River would provide at least 450,000 acre-feet if supported by offstream reservoirs to exchange water supplies in periods of low flow. Table III B-4.1 shows the water supply by existing and potential developments. About 1.8 million acre-feet are potentially available for Colstrip-Gillette development.

The Bureau of Reclamation has authorization to annually option 775,000 acre-feet of water to industry from the Wind-Bighorn River system, at Hardin, Montana. Contracts have been executed in the amount of 658,000 acre-feet and requests are pending for 295,000 acre-feet. Interest has been indicated in an additional 200,000 acre-feet or more.

WATER REQUIREMENTS

The annual water delivery requirements were predicated on steamplants operating at 85 percent load factor. The daily delivery was based on meeting the maximum daily requirement. Wet cooling towers for dissipating heat were considered the most likely choice; however, cooling ponds and flow-through type cooling were investigated.

Table III B-4.1

WATER SUPPLY AVAILABLE FOR MUNICIPAL AND INDUSTRIAL USE

Existing Reservoirs	Acre-Feet
Bighorn Basin - Downstream of Hardin, Montana 1/	1,000,000
Missouri Main-Stream - Fort Peck and Garrison Reservoirs 3/	1,000,000
Subtotal	2,000,000
Potential Reservoirs or Water Resources 2/	
Powder River and Moorhead Reservoir	100,000
Tongue River and New Reservoir	60,000
Little Bighorn River and Reservoir	40,000
Little Missouri River and Reservoirs 3/	80,000
Green River and Aqueduct to Platte River	100,000
Buffalo Bill Reservoir and Enlargement	50,000
Yellowstone River surplus flows as firmed by offstream storage reservoirs	450,000 4/
Subtotal	880,000
Estimated total water resources available	2,880,000

1/ Of this amount 775,000 acre-feet are annually optioned to industry.
2/ Water from these reservoirs or sources except from the Little Missouri could be utilized in the Gillette or Colstrip areas.
3/ All sources except these practical for Gillette-Colstrip development.
4/ Comparable costs to Hardin-Gillette.

The water delivery was assumed into a holding reservoir at the steam plantsite from which water could be withdrawn for boiler feed and cooling make-up water to offset evaporation, blow down and other losses.

Table III B-4.2 which permits a comparison of water costs between coal field locations, was based on 17.5 c.f.s. per 1,000 megawatts, which was judged to represent minimum requirements for steam generation, but would enable satisfactory comparisons of water costs between coal sites.

Tables III B-4.3 and -4.4, which compare water costs at the Gillette, Wyoming vicinity and Colstrip, Montana area respectively, were based on 28 c.f.s. per 1,000 megawatts as being more liberal and to be used for the NCPS. These water rates were judged to be adequate for steam generation and were used to determine costs of various generating capacities in terms of water deliveries solely for generation and in combination with water needs for other types of coal processing.

INVESTMENT AND ANNUAL COSTS

The cost of water delivered was based on quantities relating to installed generation capacity. Pipeline sizing was based on studies of economical size pipe for various flows, hydraulic head, and structural safety. The number of pumping lifts was determined from total lift but each lift was limited to 250 feet wherever possible. Flow-control structures were used at each 150-foot drop in elevation along any line. Each conveyance facility was estimated as a modern system which would automatically sense and adjust to varying demand.

The field costs of conveyance facilities to deliver water to each of the potential coal fields, and all engineering, supervision, administration and related indirect costs including financing and interest during construction are summarized on Table III B-4.2. Operation, maintenance, and replacement costs were estimated for a system operating almost continually during the 35-year project life.

ANNUAL COSTS OF WATER 7/
(Oct. 1970 Price Level)

Plant Location	Plant Size	Conveyance Investment 1/	Pumping Energy 2/	Replacements 3/	Operation & Maintenance	Assigned Aqueduct or Storage	Total	Per Ac.-Ft. Delivered
	(MW)	(- - - - - -	- - - - - -	- - - - $1,000	- - - - - -	- - - - - -	- - - - -)	(Dollars)
North Dakota								
Bowman #1	5,000	$1,197	$188	$ 48	$141	$1,925	$3,499	$ 64
Bowman #2	5,000	5,562	702	216	288	495	7,263	132
N of Dickinson	3,000	1,267	156	51	178	1,155	2,807	85
Dickinson	3,000	1,894	268	75	265	297	2,799	85
Dickinson and	(3,000)	2,978	600	118	323	792	4,811	55 4/
Bowman	(5,000)	2,950	312	116	257	--	3,635	121 5/
Beulah	5,000	955	112	37	29	495	1,628	30
Center	1,000	346	49	13	117	99	624	57
South Dakota								
Ludlow	1,000	631	72	25	160	385	1,273	116
Colorado								
Watkins	1,000	423	56	17	123	275	894	81
Wyoming								
W of Kemmerer	5,000	1,790	356	70	228	440	2,884	52
NE of Rock Springs	1,000	687	108	27	262	88	1,172	106
N of Wamsutter	5,000	3,153	448	124	331	440	4,496	82
Gillette Vicinity, 10 Plants	10,000 ea.	(- - - - - - - - - - St. Xavier to Gillette Aqueduct - - - - - - - - - - -)						(85-101) 6/
Spotted Horse	3,000	" " " " "						(68-80) 6/
Lake DeSmet	10,000	" " " " "						(65-73) 6/
Montana								
NW of Brockway	5,000	1,967	336	77	235	495	3,110	57
Paxton	1,000	672	68	26	157	99	1,022	93
Richey	1,000	733	88	28	213	99	1,161	106
Fort Kipp	1,000	67	12	3	27	99	208	19
Reserve	1,000	643	68	26	188	99	1,024	93
Coal Ridge	1,000	877	96	34	247	99	1,353	123
Wibaux	5,000	1,394	280	56	205	495	2,430	44
W of Savage	1,000	401	60	16	124	99	700	64
Colstrip	5,000	1,401	312	56	189	495	2,453	45
NW of Brandenburg	1,000	292	40	12	89	99	532	48
SE of Ashland	5,000	634	76	25	75	1,870	2,680	49
Birney	1,000	(- - Plant located adjacent to Tongue River - - -)				374	374	34
Birney-PJ	1,000	" " " " " "				374	374	34
S of Birney	10,000	1,041	212	41	88	3,960	5,342	49
Kirby Alt. 1	1,000	475	84	18	154	374	1,105	100
Kirby Alt. 2	1,000	1,200	40	47	94	374	1,755	160
Decker	5,000	(- - Plant located adjacent to Tongue River - - -)				1,870	1,870	34
Volborg	5,000	1,774	304	70	232	495	2,875	52
Camps Pass	10,000	4,476	912	177	374	990	6,929	63
Sonnette	1,000	428	80	17	151	319	995	90
Broadus	3,000	(- - Plant located adjacent to Powder River - - -)				957	957	29
Moorhead	5,000	" " " " " "				1,595	1,595	29

1/ Investment costs amortized over 35 years @ 3.463 percent.
2/ Energy costs computed at 4 mills per kwh.
3/ Combined replacement factor = 0.002674 x field cost.
4/ Unit cost for 88,000 acre-feet of water delivered to Dickinson; 33,000 for Dickinson plant and 55,000 for Bowman plant.
5/ Includes $54 per acre-foot for water delivered to Dickinson for Bowman plant.
6/ Cost range for medium and large size aqueducts, see Table 6A in appendix.
7/ This table is based on 17.5 c.f.s. per 1,000 megawatts of installed capacity, and should be considered as minimum required for boiler make-up water and to offset cooling tower evaporative losses.

Table III B-4.3

UNIT COST OF WATER DELIVERED IN GILLETTE AREA
(Oct. 1970 Price Level)

Aqueduct Water Deliveries and Unit Costs

MW Installed	Water for Generation A.F./Yr. 1/	Cost of Water Per Acre-Foot (Steam Plant Portion of Delivered Water) 100%	67%	50%	33%
3,000	50,000	$170.00	$149.00	$133.00	$114.00
6,000	103,000	133.00	113.00	102.00	91.00
8,000	137,000	118.00	102.00	94.00	85.00
13,000	212,000	101.00	90.00	85.00	79.00
15,000	257,000	96.00	86.00	82.00	78.00
20,000	342,000	89.00	82.00	79.00	77.00
23,000	394,000	86.00	80.00	78.00	76.50
25,000	427,000	84.00	79.00	77.00	76.00
30,000	510,000	82.00	78.00	76.50	76.00
40,000	685,000	79.00	76.50	76.00	76.00
50,000	855,000	77.00	76.00	76.00	76.00

1/ Based on 28 c.f.s. per 1,000 MW installed capacity as suggested in Chapter X of National Power Survey.

UNIT COST OF WATER DELIVERED IN COLSTRIP AREA
(Oct. 1970 Price Level)

Aqueduct Water Deliveries and Unit Costs

MW Installed	Water for Generation A.F./Yr. 1/	Cost of Water Per Acre-Foot (Steam Plant Portion of Delivered Water) 100%	67%	50%	33%
3,000	50,000	$45.00	$41.00	$37.00	$32.00
6,000	103,000	37.00	31.00	28.00	23.00
8,000	137,000	33.00	28.00	24.00	20.00
13,000	212,000	27.00	22.00	20.00	18.00
15,000	257,000	25.00	21.00	19.00	16.50
20,000	342,000	22.00	19.00	17.00	16.00
23,000	394,000	21.00	18.00	16.00	15.50
25,000	427,000	20.00	17.00	15.50	15.00
30,000	510,000	19.00	16.00	15.00	15.00
40,000	685,000	17.00	15.50	15.00	15.00
50,000	855,000	16.00	15.00	15.00	15.00

1/ Based on 28 c.f.s. per 1,000 MW installed capacity as suggested in Chapter X of National Power Survey.

Any steamplant that could be located adjacent to its water supply would not require an expensive or complex conveyance system. Assigned costs as shown in the Table represent the costs of developing or acquiring a firm water supply from existing reservoirs, new reservoirs to be constructed, or purchasing irrigated land to obtain a water right.

A consumptive use, including boiler make-up water, of 28 c.f.s. per 1,000 megawatt installed capacity greatly increases the water requirements of a plant but decreases the unit cost per acre-foot of water delivered. The increased water requirements and unit cost of water delivered to Gillette, Wyoming, are tabulated on Table III B-4.3. The last three columns of the tabulation indicate the unit cost of water when sharing the use of a pipeline system with other coal processors. It should be noted that the unit cost of water becomes less when the portion of water delivered for generation becomes less. Table III B-4.4 indicates similar cost conditions for water delivered from the Yellowstone River to Colstrip, Montana.

III C TRANSMISSION

CONCLUSIONS

The principal objective of the Transmission Committee was to develop transmission plans adequate for delivery of power generated at the coal field sites to the selected delivery buses and to estimate costs of these plans. Conclusions are drawn as follows:

1. A technically feasible transmission system can be designed and built to deliver the magnitudes of power contemplated in the study. This can be done with presently available materials and devices.

2. The highest transmission voltages possible should be used for any project of this kind, where the impact upon the environment can be thereby minimized. It was therefore concluded that the highest commercially operable voltage available, 765 kv, should be used for the Eastern System. For the Western System, where lower levels of generation are contemplated and where the transmission distances assumed were much shorter, 500 kv would serve the purpose as well as the higher voltage and at a lower cost.

3. Multiple transmission lines should be routed through common corridors in such a manner as to strike a reasonable compromise between spatial diversification for reliability reasons on the one hand and minimization of environmental impact on the other.

4. For minimizing right-of-way requirements and for economic reasons, high levels of series reactive compensation are essential.

SUMMARY

1. Task Force Functions

The Technical Studies Task Force developed a transmission system for the various stages of development and ran required load flow studies. The Design and Location Task Force developed detailed transmission facilities and unit costs for lines and substations.

2. Transmission Committee

Using information obtained from the task forces, the Transmission Committee developed estimated costs of constructing transmission for the various alternatives. These costs are shown in Tables III C-1 through III C-4. Basic transmission plans are described by Figures III C-1.1 through III C-1.8 in the Technical Studies Task Force Report.

ASSUMPTIONS AND QUALIFICATIONS

1. Corridor Routing

The purpose served by routing transmission lines through a common corridor is to improve visual esthetics. Obviously, there must be a limit to the proportion of total transmission capacity located on any one right-of-way for reasons relating to reliability. Yet, if tests for reliability can reasonably accommodate some grouping of multiple lines, this should be done to reduce overall effects of the lines upon the landscape. It was therefore assumed that, for cost estimating purposes, a plan incorporating several corridors in the ultimate development would be most suitable.

2. Delivery points were established at: Des Moines, Iowa; Gering, Nebr.; Kansas City, Mo.; Oahe Switchyard, S. D.; St. Louis, Mo.; Twin Cities, Minn.; and Utica Junction Switching Station, S. D.; for the Eastern System and at Gillette and Medicine Bow, Wyo., for the Western System.

3. For Eastern and Western Systems 765-kv a-c and 500-kv a-c transmission voltages, respectively, were used.

4. Only presently available equipment was applied, although progress in technology may allow more advanced applications. High voltage d-c transmission was not included because there is no adequate d-c circuit breaker available at the present time.

RESULTS

Estimated costs of transmission alternatives described by Technical Studies Task Force Figures III C-1.1 through III C-1.8 are listed in Tables III C-1 through III C-4. These costs include allowances for contingencies, land and land rights, clearing, access roads, service facilities, investigations, construction engineering, preparation of designs and specifications, construction supervision, and other general expense but do not include interest charges during construction.

Table III C-1

EASTERN SYSTEM
ESTIMATED TRANSMISSION COSTS
1970 Price Level

(In Millions of Dollars)

Facilities	Generation Level, MW 3,000	10,000	20,000	40,000	43,000	Annual O&M Cost * (%)
1. Transmission lines	456	807	1,273	2,288	2,568	0.4
2. Substations, switch-yards, etc.	317	583	934	1,660	1,854	1.8
3. Control & Communications equipment	15	28	44	79	88	5.0
4. Subtotal	788	1,418	2,251	4,027	4,510	
5. Allowance for improved appearance (3% of line 4)	24	43	67	121	135	
6. Total	812	1,461	2,319	4,148	4,645	

* % of total investment.

Table III C-2

EASTERN SYSTEM
ESTIMATED TRANSMISSION COSTS
1975 Price Level

(In Millions of Dollars)

Facilities	Generation Level, MW 3,000	10,000	20,000	40,000	43,000	Annual O&M Cost * (%)
1. Transmission lines	582	1,030	1,625	2,920	3,277	0.4
2. Substations, switch-yards, etc.	405	744	1,192	2,119	2,366	1.8
3. Control & Communications equipment	19	36	56	101	112	5.0
4. Subtotal	1,006	1,810	2,873	5,140	5,755	
5. Allowance for improved appearance (3% of line 4)	30	54	86	154	173	
6. Total	1,036	1,864	2,959	5,294	5,928	

* % of total investment.

Table III C-3

WESTERN SYSTEM
ESTIMATED TRANSMISSION COSTS
1970 Price Level

(In Millions of Dollars)

Facilities	Generation Level, MW 1,000	3,000	10,000	Annual O&M Cost (%)
1. Transmission lines	45.5	71.0	139.0	0.4
2. Substations, switchyards, etc.	25.0	75.0	150.0	1.8
3. Control & communications equipment	1.5	3.0	6.0	5.0
4. Subtotal	72.0	149.0	295.0	
5. Allowance for improved appearance (3% of line 4)	2.0	4.5	9.0	
6. Total	74.0	153.5	304.0	

Table III C-4

WESTERN SYSTEM
ESTIMATED TRANSMISSION COSTS
1975 Price Level

(In Millions of Dollars)

Facilities	Generation Level, MW 1,000	3,000	10,000	Annual O&M Cost (%)
1. Transmission lines	58.0	90.5	177.5	0.4
2. Substations, switchyards, etc.	32.0	95.5	191.5	1.8
3. Control & communications equipment	2.0	4.0	7.5	5.0
4. Subtotal	92.0	190.0	376.5	
5. Allowance for improved appearance (3% of line 4)	3.0	5.5	11.5	
6. Total	95.0	195.5	388.0	

For purposes of estimating interest during construction, costs for all of the alternatives, for both Eastern and Western development, was spread as follows:

Year	Percent of total completion
1	5
2	20
3	40
4	30
5 (completion)	5
	100

This 5-year period was selected because of the unusually large size of the transmission construction.

Table III C-5 shows costs of transmission for the various alternatives in dollars per kilowatt transmitted.

III C-1 TECHNICAL STUDIES

RESULTS

The basic charge of the Technical Studies Task Force was to determine transmission systems to deliver the generated power to load centers. The Task Force also was to determine certain reserve requirements and transmission losses.

With the aid of computer power flow studies, the following were developed for the generation levels studied:

EAST SYSTEM

System development at selected load levels of 3,000 mw, 10,000 mw, 20,000 mw, and 40,000 mw are shown on Figures III C-1.1, -1.2, -1.3, and -1.4, respectively.

The 3,000-mw development level was overlaid on the projected 1980 base transmission system. From these studies it appears that the UHV system will have little adverse effect on the underlying system and the underlying system will have little beneficial effect on the UHV system.

The development of the transmission system for the generation level of 43,000 mw (includes 3,000 mw of hydropeaking) indicates a system of fourteen 765-kv lines arranged in four corridors would be adequate to deliver the generated power under the study criteria and assumptions. System configuration and loading for the 43,000-mw delivery are shown on Figure III C-1.5.

WEST SYSTEM

The West System considered only one delivery point, Medicine Bow, Wyoming, in addition to a local bus delivery. Power levels of 1,000 mw, 3,000 mw, and 10,000 mw were studied and 500-kv transmission was selected.

The transmission for the West System is as shown on Figures III C-1.6, III C-1.7, and III C-1.8, respectively.

Table III C-5

TRANSMISSION UNIT COSTS

Generation level (mw)	Estimated costs (millions of $)		Unit cost ($ per kw transmitted)		Decrease in unit cost* (percent)
	1970	1975	1970	1975	
Eastern System					
3,000	812	1,036	270.7	345.3	-
10,000	1,461	1,864	146.1	186.4	46.0
20,000	2,319	2,959	116.0	148.0	20.6
40,000	4,148	5,294	103.7	132.4	10.6
43,000	4,645	5,928	108.0	137.9	-4.2
Western System					
1,000	74	95	74.0	95.0	-
3,000	154	196	51.3	65.3	30.7
10,000	304	388	30.4	38.8	40.7

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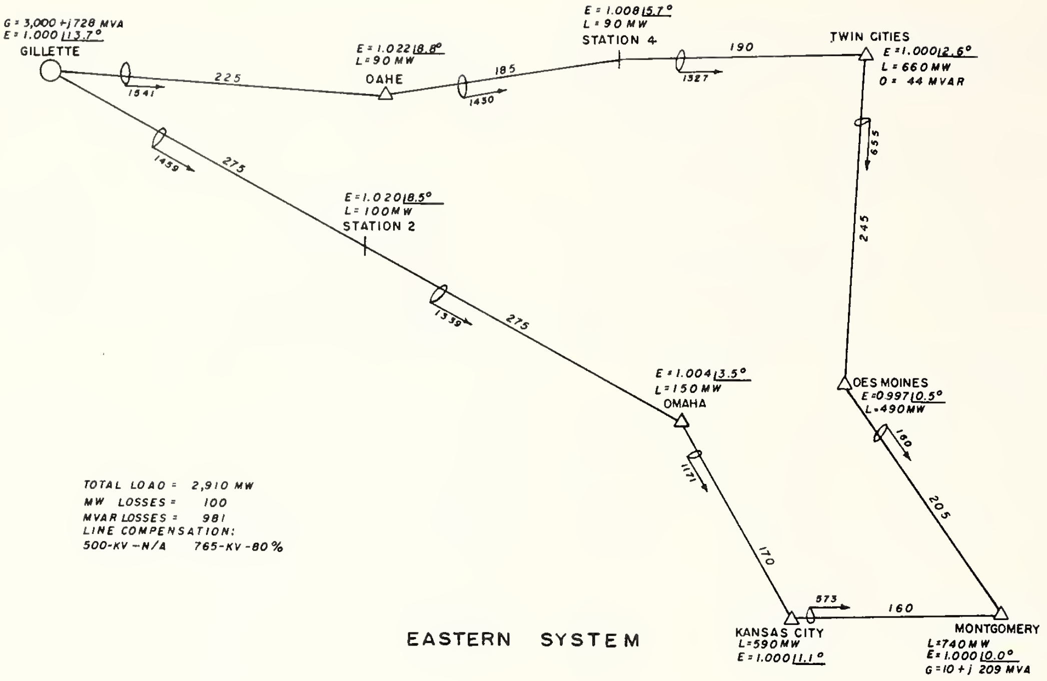
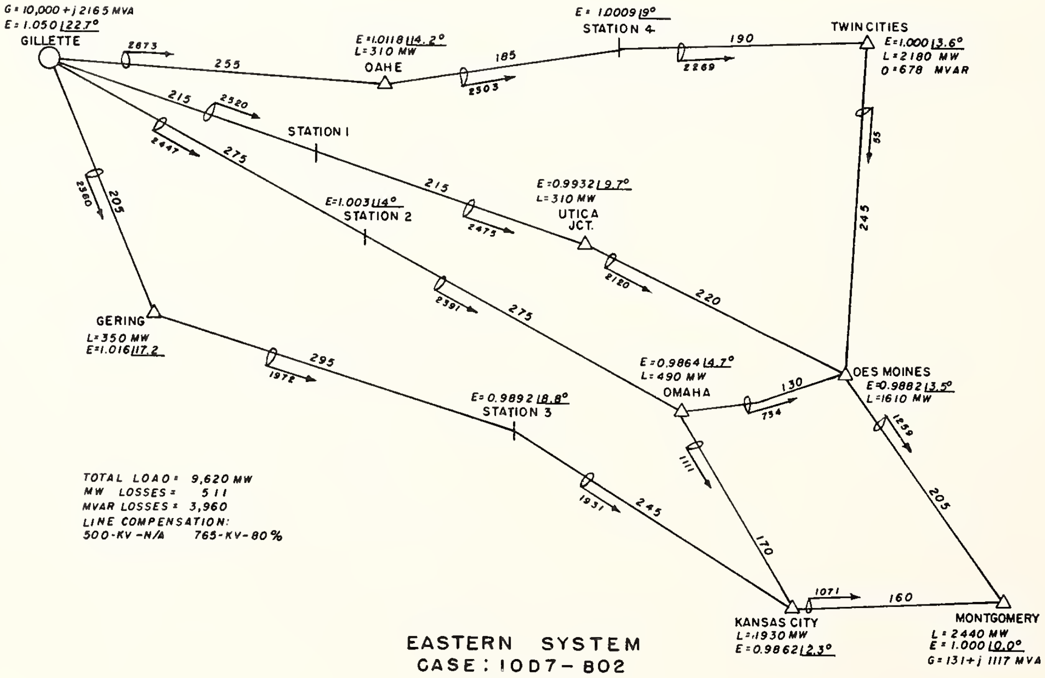
* Relative to next lower generation level.

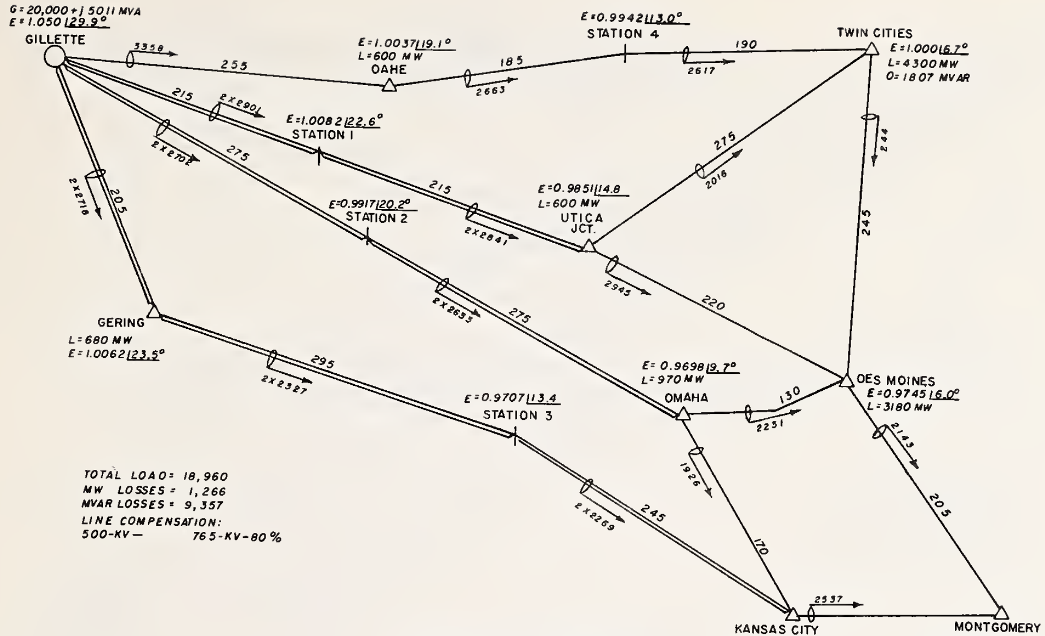


EASTERN SYSTEM

Figure IIIC-1.1

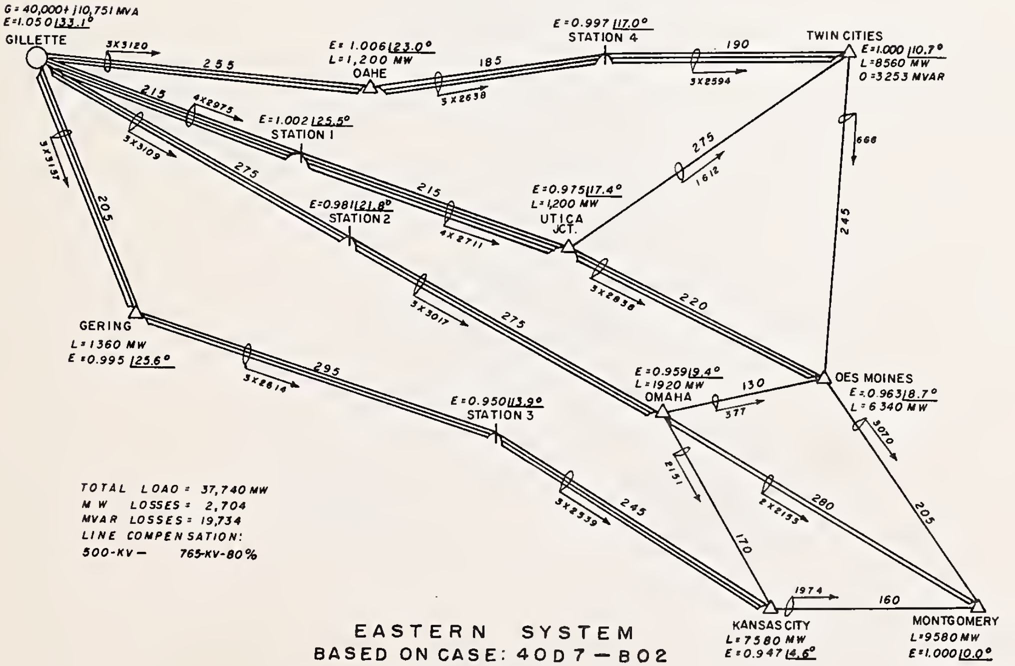


EASTERN SYSTEM
CASE: 10D7 – 802
Figure IIIC-1.2



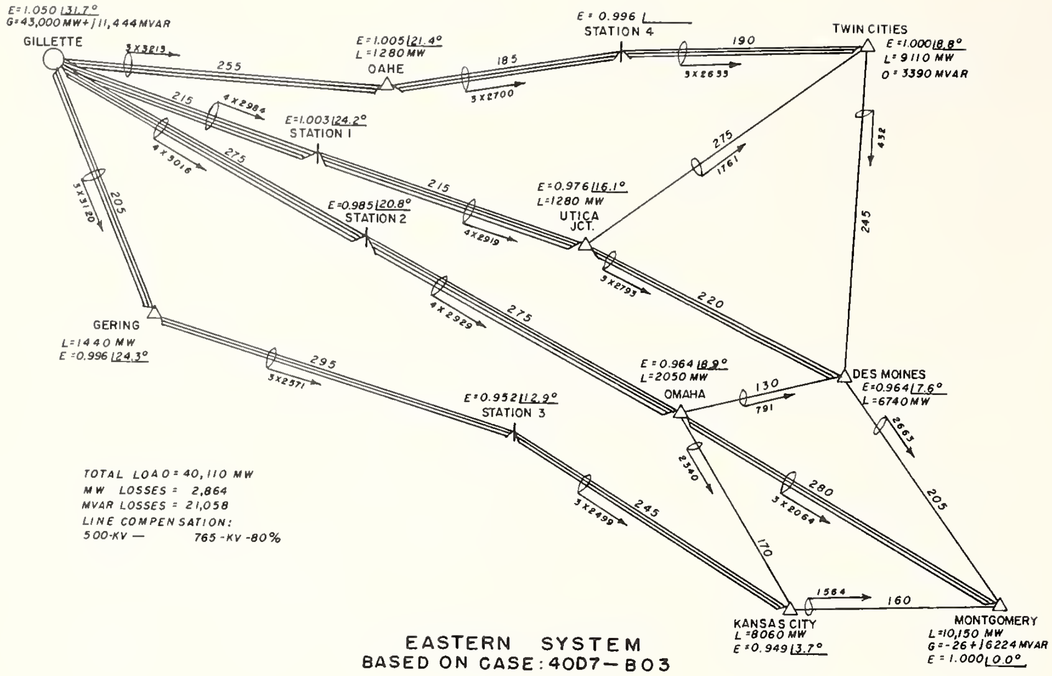
TOTAL LOAD = 18,960
MW LOSSES = 1,266
MVAR LOSSES = 9,357
LINE COMPENSATION:
500-KV — 765-KV-80%

EASTERN SYSTEM
CASE: 20D7-B02
Figure IIIC-1.3



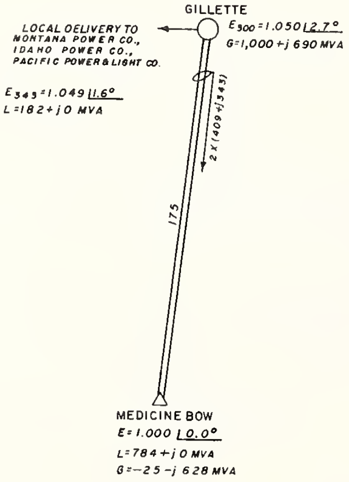
TOTAL LOAD = 37,740 MW
MW LOSSES = 2,704
MVAR LOSSES = 19,734
LINE COMPENSATION:
500-KV — 765-KV-80%

EASTERN SYSTEM
BASED ON CASE: 40D7-B02
Figure IIIC-1.4



TOTAL LOAD = 40,110 MW
MW LOSSES = 2,864
MVAR LOSSES = 21,058
LINE COMPENSATION:
500-KV — 765-KV-80%

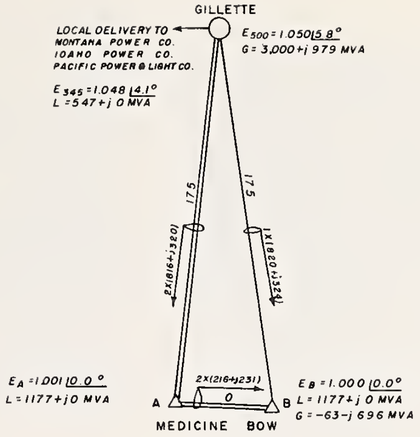
EASTERN SYSTEM
BASED ON CASE: 40D7—B03
Figure IIIC-1.5



TOTAL LOAD = 966 MW
MW LOSSES = 9
MVAR LOSSES = 62
LINE COMPENSATION:
500-KV—70%

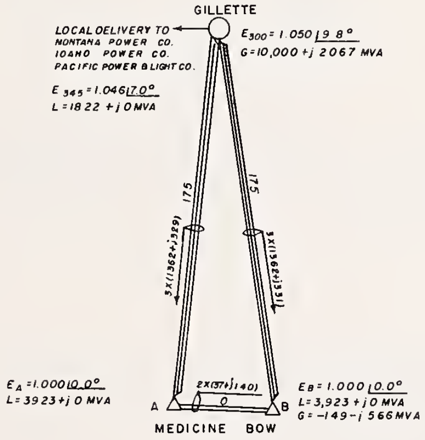
WESTERN SYSTEM

Figure IIIC-1.6



TOTAL LOAD = 1,901 MW
MW LOSSES = 36
MVAR LOSSES = 283
LINE COMPENSATION:
500-KV – 70 %

WESTERN SYSTEM
CASE: 03W5 – B01
BASED ON CASE: 01W5 – B01
Figure IIIC-1.7



TOTAL LOAD = 9,668 MW
MW LOSSES = 183
MVAR LOSSES = 1,501
LINE COMPENSATION:
500-KV – 70 %

WESTERN SYSTEM
CASE: 10W5 – B01
BASED ON CASE: 03W5 – B01
ADDED ONE GILLETTE-MEDICINE BOW "A"
AND TWO GILLETTE-MEDICINE BOW "B" LINES
Figure IIIC-1.8

RESERVE REQUIREMENT

Based on normal maintenance at the generation complex and considering a forced outage rate of 5 percent for 500-mw units and 7 percent for 1,000-mw units, the additional generation shown in Table III C-1.1 is required to maintain a transmission load factor of over 90 percent, except for the lowest level of development. With the transmission systems developed for each generation level (above the 3,000-mw level) and the installation of additional units at the plant for normal maintenance scheduling, it may be possible to effect a reduction in load area generation for reserve purposes. For example, at the 40,000-mw level of development, with 44,500 mw of installed generation, the transmission system is capable of transmitting full plant output with all lines in service. The ability to incorporate the plant generation into overall system reserves depends upon system load factor, duration of the maintenance period for system units, seasonal load variations, and transmission reliability.

For transmission line outages and generator forced outages, the reserve requirement is assumed to be supplied in the load area. The maximum load area reserve requirement for a double-line outage on the 765-kv transmission was determined to keep the loading of remaining lines within acceptable limits. Table III C-1.2 shows the analysis of system reserve requirements.

Table III C-1.1

ADDITIONAL GENERATION REQUIREMENTS

Development level and number of units				Additional units	Installed capacity	Transmission load factor percent
level	system	500 mw	1,000 mw			
3,000 mw	east	6		0	3,000	85
1,000 mw	west	2			1,000	
10,000 mw	east	6	7	1-1,000	11,000	91
3,000 mw	west	6			3,000	
20,000 mw	east	6	17	2-1,000	22,000	92
3,000 mw	west	6			3,000	
40,000 mw	east	6	37	4-1,000	44,500	92
10,000 mw	west	6	7	1- 500	10,000	

Table III C-1.2

SYSTEM RESERVE REQUIREMENTS

Development level	Total area load	Load area reserve @ 15 percent of load	Reserve required at load for loss of two lines
EAST			
3,000	30,000	4,500	3,000
10,000	60,000	9,000	1,350
20,000	90,000	13,500	1,000
40,000	150,000	22,500	0
WEST			
1,000	1,000	1,500	800
3,000	20,000	3,000	0
10,000	40,000	6,000	0

TRANSMISSION FOR PLANT WATER SUPPLY

A 230-kv line from a point on the Yellowtail-Custer transmission line near Hardin, Montana, to a proposed Wyodak, Wyoming, 230-kv switching station would be adequate to supply loop power service to the pumping plants for supplying water to the generating powerplants. The cost of this facility is included in the estimates of water costs.

SYSTEM GENERATION AND LOSSES

Estimated annual generation energy input to the transmission system is shown in Table III C-1.3 for each development level. Capacity and energy losses obtained from system power flow studies for normal conditions are also shown. A loss factor equal to 0.7 (Load Factor)(squared) + 0.3 (Load Factor) was used in obtaining energy losses.

Table III C-1.3

ENERGY INPUT AND SYSTEM LOSSES

Generation capacity	Gen-energy mw - yrs/yr	System loss		System losses mw - yrs/yr
		mw	percent	
EAST				
3,000	2,550	100	3.30	76
10,000	9,100	511	5.11	435
20,000	18,400	1,266	6.33	1,100
40,000	36,800	2,704	6.76	2,360
* 43,000	36,500	2,864	6.66	2,500
WEST				
1,000	850	9	0.90	7
3,000	2,745	36	1.20	31
10,000	9,200	183	1.83	159

---

* Energy for pumping was obtained from the generating complex during offpeak periods and would be about 1,000 mw - yrs/year.

ASSUMPTIONS AND QUALIFICATIONS

This work was based on the following assumptions and qualifications that were established before the study was initiated or introduced as the work progressed:

1. The East-West ties were open, necessitating two study areas, an East System area and a West System area.

2. Voltage levels of the transmission system would be limited to existing technology and available equipment, presently a maximum of 765 kv.

3. Power would be delivered from mine-mouth plants to load center delivery points, at levels of about 30 percent of area load growth. Minimum generation considered for the study was 3,000 mw on the East System and 1,000 mw on the West System.

4. The phase angle between the generation area voltage and the load center voltage would be within 30 degrees for normal system conditions and 42 degrees for outages. These criteria were considered substitutes for actual computer stability studies.

5. Series capacitor compensation up to 80 percent was used for 500- and 765-kv lines.

6. The East System was designed to meet MARCA reliability requirements, and the West System was designed to meet WSCC reliability requirements.

7. The reserve requirement for a transmission line or generation-forced outage would be supplied by the receiving system.

8. The additional generation required for generator maintenance would be supplied at the generation area.

III C-2 DESIGN AND LOCATION

COST ESTIMATING DATA
(October 1970 prices)

The costs in Table III C-2.1 were used in estimating the total cost of the transmission systems studied. The costs include allowances for contingencies, land and rights, clearing, access roads, service facilities, investigations, construction engineering, preparation of designs and specifications, construction supervision, and other general expenses, but at this point do not include an allowance to minimize environmental impact.

DESIGN ASSUMPTIONS

The following design assumptions were used:

1. Transmission lines.

    a. Towers to be galvanized steel lattice type.

    b. Self-supporting towers were selected for costing purposes.

    c. Effort should be made to slenderize tower outline and to minimize use of secondary members to improve appearance.

    d. Rights-of-way for transmission lines would not require fencing.

    e. Conductor sizes were selected on the basis of audible corona noise considerations and are larger than usually required on an economic basis. It may be possible to develop an economical expanded self-damping conductor for final designs.

    f. Not more than four corridors would be used for the lines to the east.

    g. The number of separate rights-of-way per corridor would not exceed two.

    h. The minimum distance between rights-of-way would be 0.75 mile.

    i. The number of circuits per right-of-way would not exceed two.

    j. Joint utilization of rights-of-way considered desirable, but decision in this regard should be made at national level. One concept would be to have major corridors 1 mile wide, spaced 100 miles or more apart, and used for highways, railroads, overhead transmission lines, underground transmission lines, gas lines, oil lines, communications lines, water lines, parks, etc. Minor corridors at shorter intervals could be added as needed.

2. Substations, switchyards, etc. -

    a. Uncluttered low-profile type.

    b. No guyed structures adjacent to substations.

    c. No latticed structures in substation.

    d. Equipment and structures to be painted except that galvanized steel would be used for structures which, if painted, would require bus outages for periodic repainting.

    e. Ring bus arrangement, convertible to breaker-and-one-half scheme, would be used for up to six circuits.

    f. Breaker-and-one-half scheme used for more than six circuits.

    g. Bus sectionalizing breakers included to increase reliability when more than twelve circuits installed.

    h. To limit switchgear duty and minimize loss of transmission capability, switching stations or substations were included whenever 765-kv line lengths exceed 300 miles. All reactors and line compensation would be located in these stations.

    i. Six plant sites covering a distance of approximately 40 miles were assumed at the Gillette-Colstrip complex area.

3. Transmission System Location.

    a. Most direct routes that would have minimum environmental impact were used.

    b. It was assumed that substations would be located 20 to 30 miles outside city limits.

    c. Additional costs to conform to environmental criteria would not exceed 3 percent of total investment costs.

III D ENVIRONMENTAL

The complete report of the Environmental Committee is included in section II G earlier in this volume.

III D-1 POLLUTION CONTROL

The Pollution Control Task Force has examined the methods and costs of controlling air and water pollution to meet the state and Federal standards. In the case of air pollution, allowable emissions suggested in the Federal Register dated April 7, 1971, have been assumed. These are generally at least as strict as comparable emission regulations in the states covered by the study. State-Federal water quality standards have been adopted by each state in the study area. These standards generally provide some allowance for degradation due to salinity and an allowable temperature rise of 4 to 5 degrees Fahrenheit. All states in the study area, however, have adopted a nondegradation policy which would make any substantial stream water quality degradation impossible.

COST OF TRANSMISSION FACILITIES

Transmission lines (single circuit AC)

(1)	765 kv (4-1,272 kem/phase)	$230,000 per mile
(2)	500 kv (3-1,113 kem/phase)	130,000 per mile
(3)	230 kv (1-954 kem/phase)	44,000 per mile

Transformers

		1,800 mva (cost)	1,200 mva (cost)	900 mva (cost)	600 mva (cost)
(1)	765/500 kv	$2,800,000	$2,200,000	$1,950,000	$1,700,000
(2)	765/345 kv	3,500,000	2,700,000	2,300,000	1,900,000
(3)	500/345 kv				1,400,000

Power circuit breakers (design for three breakers per bay)

		765 kv	500 kv
(1)	One breaker initially	$2,200,000	$1,200,000
(2)	Two breakers initially	2,750,000	1,500,000
(3)	Adding one breaker to (1) or (2)	650,000	360,000
(4)	Three breakers initially	3,300,000	1,800,000

Reactors with switch

(1)	765 kv, 600 MVAR	$1,800,000
(2)	500 kv, 200 MVAR	900,000

Series compensation station

765 kv, 2,000-MVAR range - $440,000 + $8/KVAR
500 kv, 800-MVAR range - $290,000 + $7/KVAR

Step-up two-winding transformers

765 kv, 800 to 1,200 mva	$850,000 + $1.30/kva
765 kv, 50 mva	$570,000 + $230/kva
500 kv, 800 to 1,200 mva	$600,000 + $1.25/kva

Communications and control - Approximately 2 percent of total investment cost.

Annual operations and maintenance costs in percent of total investment -

Transmission lines - 0.4 percent
Substations, switchyards, etc. - 1.8 percent
Control and communications - 5.0 percent

FLY ASH COLLECTION

The Task Force findings indicate that fly ash collection equipment capable of 99.5 percent efficiency when using low sulfur coal will require special selection and design.

SULFUR OXIDE CONTROL

The allowable emissions proposed in the Federal Register dated April 7, 1971, suggests that scrubbing is feasible and that 0.7 percent sulfur coal is an acceptable alternative. Since the average sulfur content of the coals being studied is around this figure, scrubbing may not be necessary.

According to a Federal Power Commission report, some 40 different sulfur oxide processes have been suggested and tested but no acceptable technology exists. For purposes of discussion, the Task Force prepared a cost estimate for one possible system. This system is a wet limestone process which would remove fly ash as well as sulfur dioxide.

NITROGEN OXIDE CONTROL

The limit of about 500 ppm of nitrogen oxides proposed in the April 7, 1971, Federal Register is generally believed to be within the capability of the kind of boiler assumed for the study.

FUGITIVE DUST

The national proposed limit of no visible fugitive dust escaping beyond property lines should be attainable with normal dust control.

ASH DISPOSAL

Special operating methods of covering ash disposal areas will probably have to be used. The method used may vary depending on whether scrubbers or precipitators are used for ash collection. Most of the ash must be conveyed to an onsite storage area. Integration of coal stripping and ash disposal will be required to obtain the lowest costs.

TYPE OF COOLING

Many methods and variations of these methods are available for heat rejection. These methods include once-through cooling, cooling ponds, spray ponds, mechanical and natural draft wet-cooling towers, and mechanical and natural draft dry-cooling towers. Selection of the type of cooling is based on many factors relating to the site and other economic conditions.

Although wet-cooling towers were selected early in this study, the Task Force investigation indicates there may be savings by the use of cooling ponds.

IMPACT

Water pollution presents no major obstacle which cannot be handled by careful design, but may involve additional expenditures over those which have been experienced in the past. If cooling towers are used, careful consideration will have to be given to the method of handling the blowdown. This may require evaporation ponds unless adequate chemical treatment can be provided to meet standards for water being returned to its source of supply. Wet-cooling towers can produce objectionable plumes, fog,and increase the duration of fog. The extent to which this will be a problem will depend upon meteorological conditions.

COOLING WATER ALTERNATIVES

The Task Force reviewed and evaluated the cooling and brine disposal facilities required at the proposed installation to assure that state-Federal water quality requirements will be met. Three main cooling device alternatives; cooling ponds, wet-cooling towers, and dry-cooling towers were considered.

In the North Central Power area, the advantages of a cooling pond would be low cost because of low land value and good efficiency because of climatological factors.

The principle of dry-type cooling appears to be attractive; however, dry-type coolers are expensive and have not been proven in the sizes required for the NCPS units.

EVALUATION OF COOLING ALTERNATIVES

The Pollution Control Task Force study indicates that dry-type cooling towers can compete with wet-cooling towers if water costs exceed $154 per acre-foot. It was assumed in this study that no stream could accept heated discharges or return flows in excess of 1,000 ppm Total Dissolved Solids (TDS) except the Powder River, which could accept return flows as high as 1,100 ppm TDS. An evaporative pond or other disposal facility must be used in conjunction with wet tower in all cases evaluated in this study to capture the blowdown which is too high in salt concentration to be released to a stream.

The cheapest and most efficient cooling device that could be used in this area is a cooling pond. Under the stream water quality criteria established in this evaluation the Missouri River, South Platte River, Green River, Yellowstone River, and Tongue River sources could be used for flow-through cooling and return to the stream. Bighorn River aqueduct water could be used in the Powder River Basin if makeup water were increased to 22,900 acre-feet per 1,000 mw plant per year. Powder River water would be unacceptable for flow-through cooling pond use.

III D-2 LAND RECLAMATION

This report deals with mined-land reclamation because right-of-way reclamation poses no unusual problems. As reflected in the detailed report of the Land Reclamation Task Force, rights-of-way can be reclaimed adequately for $18 to $35 per acre, including leveling, soil preparation, fertilizing and seeding.

Basically, the reclamation of spoils throughout the area of the North Central Power Study must be kept simple using native varieties common to the area and which are able to regenerate and maintain themselves without constant care. More and more the mining companies must lead the way in determining a use for the mined areas and then must follow through with reclamation to achieve that usage.

MONTANA

The coal reserves for surface mining are located mainly in Eastern Montana. Reclamation of this area has proven costly because of the heavy overburden and climatic conditions. Natural restoration of vegetation does not readily occur here.

The Montana Agricultural Experiment Station has conducted reclamation experiments at Colstrip including use of tubed seedlings, plastic moisture catch basins, fertilizer programs, and comparison of various trees, shrubs and grasses.

Knife River Coal Mining Company reclamation at Savage started in 1965. The spoils support vegetation, primarily grasses. Reclamation costs range up to a maximum of $500 per acre when leveling these spoils to slopes of 25 percent or less. Restoration generally is successful on the first attempt. The Soil Conservation Service has also become involved in reclamation studies.

The reclamation law requires a reclamation contract between the state and the operator with generally stringent requirements to return lands to their highest potential usage. The operator can receive a partial refund of coal mine license tax for reclamation work completed.

NORTH DAKOTA

North Dakota's coal reserves occur in the western half of the state. The rainfall in this area varies from 13 inches in the west to 15 inches in the east. Spoils are not toxic and runoff is minimal, so adjacent areas and waters are not affected. Reclamation costs probably average about $350, but vary from $120 to $500 per acre, depending on the amount of dirt work required. Over a long period of time many of the older mines have become naturally revegetated.

Any operator engaged in surface mining in North Dakota with overburdens exceeding 10 feet must obtain a permit. The bond fee for this permit is based on acreage disturbed. The operator must obtain approval of his reclamation plan and submit annual reports. Lands must be restored to best usage, i.e., forestry, grazing, croplands, haylands, wildlife habitat, recreation, etc. Various degrees of leveling are required according to planned usage.

WYOMING

The semiarid conditions throughout the coal regions make reclamation most difficult. Reclamation to date has had mixed results with success in some areas in establishing grasses and other vegetation. Irrigation is very limited; however, it has been demonstrated that the soil materials in the spoils will support an adequate cover with proper fertilization and seeding. Spoils in Wyoming are not toxic and mined areas are self contained.

Most of Wyoming's mining is remote from population centers and located on low value land. Little earth moving has been required in the past and spoils such as at Glenrock require no earth work because of the method of mining. Reclamation costs may vary from less than $100 to nearly $500 per acre. (See Table III D-2.1.)

In Wyoming spoils must be graded to a rolling topography, with water impoundment where possible and protection of adjacent areas and water from toxic materials, siltation, etc.

III E ECONOMICS

PURPOSE AND SCOPE

The Economics Committee was formed to accumulate the cost data as developed by the other committees and develop an overall cost analysis for the various parts of this study. The Economics Committee was also directed to estimate the necessary property taxes and interest charges to apply during the construction period to complete the data developed by the other committees.

In the course of the study, the Coordinating Committee decided that the Gillette-Colstrip area should be used for study purposes as the site for the generation complex development. As a result,the Economics Committee has developed overall system costs only for the Gillette area sites.

The following sections summarize the economic factors for each portion of the overall development.

WATER AND COAL DELIVERIES

The water supply Task Force developed the anticipated costs of water delivery to the Gillette area for the various ultimate sizes of the generation complex. These costs are summarized in mills/kwh generated on Table III E-1 and assume that the generation complex uses 100 percent of the delivered water. These costs include both the annual revenue requirements on the capital expenditure and the operating costs such as labor, maintenance, and energy costs for the pumping.

The water supply costs were determined assuming Federal government construction and operation of the aqueducts and all associated equipment. The financial arrangements considered in this analysis were based on a 3.463 percent interest rate which is the rate applicable for fiscal year 1971 under provisions of the Water Supply Act of 1958, as amended. This rate was used for both interest during construction and to determine the annual revenue requirements on the capital investment assuming a 50-year life of the water supply facilities. A 50-year life can be used for the supply facilities even though the generating plant life has been assumed to be only 35 years. This is practical

Table III D-2.1

COST PER ACRE FOR LEVELING OVERBURDEN PILES

Width of Pit (feet)	PER CENT GRADE						
	0	4	8	12	16	20	24
50	$108.92	$103.46	$ 98.04	$ 92.58	$ 87.16	$ 81.70	$ 76.25
60	130.68	124.15	117.61	111.08	104.54	98.01	91.48
70	152.47	144.86	137.24	129.60	121.99	114.37	106.76
80	174.26	165.54	156.84	148.12	139.43	130.71	121.99
90	196.02	186.22	176.42	166.64	156.84	147.04	137.24
100	217.81	206.93	196.65	185.14	174.26	163.37	152.50
110	257.35	244.47	231.62	218.75	205.90	193.02	180.15
120	300.08	285.08	270.07	255.10	240.10	225.09	210.09
130	335.58	318.82	302.05	285.25	268.48	251.71	234.94
140	372.70	354.09	335.45	316.80	298.19	279.58	260.96
150	411.40	390.83	370.26	349.72	329.15	308.58	288.01
160	464.65	441.43	418.21	394.96	371.74	348.52	325.30
170	507.42	482.07	456.69	431.35	405.96	380.62	355.27
180	551.80	524.21	496.62	469.07	441.48	413.90	386.31
190	613.08	582.44	551.80	521.16	490.52	459.88	429.24
200	677.63	643.78	609.88	576.03	542.14	508.28	474.43

COST OF WATER REQUIRED FOR GENERATION

Installed Capacity (mw)	Delivered Water Costs	
	1970 mills/kwh	1975 mills/kwh
3,000	.393	.502
6,000	.308	.393
8,000	.273	.349
13,000	.234	.298
15,000	.222	.284
20,000	.206	.263
23,000	.199	.254
25,000	.194	.248
30,000	.190	.243
40,000	.183	.233
50,000	.178	.227

because the available coal in the Gillette area would allow two or more developments of the maximum size this study considered.

The pipeline size was optimized for each level of development. Therefore the costs shown on Table III E-1 cannot be used to determine the water supply costs during interim development of the generation complex.

The coal and byproducts Task Force has estimated coal costs in the Gillette area to be between 11 and 12 cents per million B.t.u.'s at the mine-mouth in 1970 prices. An additional .3 to .4 cents per million B.t.u.'s must be added to cover the cost of transporting the coal from the mine to the actual plant site. About .15 cent/MBTU must also be included for land reclamation. Including the above costs and assuming 5 percent annual escalation, the 1975 fuel costs would be about 16 cents/MBTU at the generator.

GENERATION PLANT COST

The basic generating unit capital costs were developed by the Thermal Generation Task Force. The construction period and the portion of the total plant costs that would be spent each year was also furnished by the Thermal Generation Task Force. To these base costs the Economics Committee has added the property tax and interest charges that would be incurred during construction. A nominal 1 percent annual property tax rate during the construction period was based on consideration of the rural nature of the area, and the magnitude of the generating complex. This tax rate assumes that the current year's taxes are based on the total expenditure for all previous years. As a result the total property taxes paid during the construction period amount to approximately 1.4 percent of the total cost.

A nominal 7 percent rate was used as the average interest rate during the construction period, considering the mix of participants and average interest rates for investor-owned utilities, cooperatives, and municipals. This was applied each year to the total construction of all previous years plus one-half of the current year's expenditures based on the premise that the construction expenditures would be uniform throughout the year. The total interest charged during construction amounts to about 13 percent of the total investment. The generating plant cost for two 500 mw units and two 1,000 mw units are summarized on Table III E-2.

As is shown on Table III E-2, the cost of providing a 60-day emergency coal storage stockpile is assumed to be

Table III E-2

GENERATING PLANT CONSTRUCTION COSTS

	$/kw	
	1970	1975
2-500 mw units		
Plant Cost	158	202
Property taxes during construction	2.8	2.2
Interest during construction	21.0	26.8
Emergency Coal Storage	1.6	2.0
Total	183	234
2-1,000 mw units		
Plant Cost	124	158
Property taxes during construction	1.7	2.2
Interest during construction	16.5	21.0
Emergency Coal Storage	1.6	2.0
Total	144	183

capitalized and is included with the total cost of the plant. Although this method of accounting for the cost of providing an emergency coal supply is not precisely accurate, for the purposes of this study it does provide a reasonable method of accounting for a rather significant cost item.

Annual operating costs were obtained primarily from the Thermal Generating Task Force with an additional 30 percent adjustment to the O&M costs to include administration and general expenses and all labor fringe benefits and are summarized on Table III E-3. The major operating expenses besides fuel are the operating and maintenance labor and the cost of ash disposal.

The required capital investment and annual operating costs for the two pumped storage sites selected for this study are summarized on Table III E-4; the cost information having been obtained primarily from the Hydrogeneration Task Force. Property taxes and interest charges during the construction period have been allocated in an identical manner as for thermal generation following the construction schedule provided by the Hydrogeneration Task Force.

The pumping energy cost as determined by the Hydrogeneration Task Force is approximately 1.5 times the energy production cost of the thermal development. The cost of this energy has been calculated as the net cost of energy at the mine-mouth plant adjusted for 1 percent nominal transmission losses to deliver this power to the pumped storage site. The annual O&M costs are based on 2,000 hours generating and 3,000 hours pumping and include administrative and general expenses and labor fringe benefits. These are shown on Table III E-4 in terms of energy actually generated.

TRANSMISSION COSTS

The total construction costs for the transmission system necessary for reliable operation at the various levels of generation were obtained from the Transmission Committee. To these costs again have been added the property taxes and interest charges during the construction period. The required capital expenditure and annual operating and maintenance costs are summarized on Table III E-5 for both the Eastern and Western Systems.

DEVELOPMENT LEVELS

The guidelines for this study were to obtain the total system costs for various levels of development of the generation. No attempt was made to determine the timing of progression from one stage of development to the next. The total investment and total annual operating costs for each level of development are summarized on Table III E-6 and III E-7, respectively. These costs are based on the actual capacity and energy delivered to the participating system as determined by the Transmission Committee and include the additional generators required at the coal fields for maintenance.

Table III E-3

GENERATING PLANT PRODUCTION COSTS

	mills/kwh	
	1970	1975
2-500 mw units		
Fuel Cost*	1.19	1.52
O&M	.59	.74
Ash Disposal	.10	.13
Total	1.88	2.39
2-1,000 mw units		
Fuel Cost**	1.14	1.46
O&M	.33	.42
Ash Disposal	.10	.13
Total	1.57	2.01

* Based on 12.5¢/B.t.u. 1970 and 16¢/MB.t.u. 1975 coal cost, 9,500 B.t.u./kwh net plant heat rate.

**Based on 12.5¢/B.t.u. 1970 and 16¢/MB.t.u. 1975 coal cost, 9,100 B.t.u./kwh net plant heat rate.

Table III E-4

PUMPED STORAGE PLANT COSTS

	Construction Costs $/kw	
	1970	1975
Rockwood-Cutler Park 1,760 mw	139	177
Property taxes during construction	2.6	3.4
Interest during construction	22.8	29.0
Total	164	209
Sheep Mountain 1,240 mw	175	223
Property taxes during construction	3.3	4.2
Interest during construction	28.7	36.6
Total	207	264

	Annual Operation Costs mills/kwh	
	1970	1975
Rockwood-Cutler Park		
Pumping Energy	2.41	3.09
O&M*	1.22	1.55
Total	3.63	4.64
Sheep Mountain		
Pumping Energy	2.41	3.09
O&M*	1.12	1.42
Total	3.53	4.51

* Based on 20 percent capacity factor.

Table III E-5

TRANSMISSION CONSTRUCTION COSTS
($1,000,000)

	Western System			Eastern System				
	1,000 mw	3,000 mw	10,000 mw	3,000 mw	10,000 mw	20,000 mw	40,000 mw	43,000 mw
Transmission Lines	46	71	139	456	807	1,273	2,288	2,568
Substations	25	75	150	317	583	932	1,657	1,853
Control	1	3	6	15	28	44	79	88
Appearance	2	5	9	24	43	67	121	135
Property Tax during Construction	1	3	6	15	28	44	79	88
Interest during Construction	12	26	51	136	245	389	696	780
Total 1970 Costs	87	183	361	963	1,734	2,749	4,920	5,512
Total 1975 Costs	111	234	461	1,229	2,213	3,508	6,278	7,034
1970 O&M Costs	.7	1.8	3.6	8	15	34	43	48
1975 O&M Costs	.9	2.3	4.6	11	19	31	55	61

Table III E-6

SUMMARY OF CAPITAL INVESTMENT REQUIRED FOR DEVELOPMENT
($1,000,000)

	Western System			Eastern System				
	1,000 mw	3,000 mw	10,000 mw	3,000 mw	10,000 mw	20,000 mw	40,000 mw	43,000 mw
Generating Plant*	183	582	1,723	549	1,668	3,252	6,378	6,923
Transmission System	87	183	361	963	1,734	2,775	4,923	5,513
Total 1970 Costs	270	765	2,084	1,512	3,402	6,027	11,301	12,436
Total 1975 Costs	345	976	2,659	1,929	4,342	7,691	14,421	15,870
Net Capacity to Participating Systems (mw)	991	2,964	9,817	2,900	9,489	18,734	37,296	41,136
Total 1970 $/kw	272	258	212	521	358	321	303	302
Total 1975 $/kw	347	329	271	665	457	410	387	385

* Additional units required for maintenance are shared by Western and Eastern systems in proportion to share of complex.

Table III E-7

SUMMARY OF ANNUAL ENERGY PRODUCTION COST
($1,000)

	Western System			Eastern System				
	1,000 mw	3,000 mw	10,000 mw	3,000 mw	10,000 mw	20,000 mw	40,000 mw	43,000 mw
Cooling Water	2,928	5,616	14,365	8,803	18,673	32,039	57,316	57,316
Fuel	8,866	28,560	93,198	26,656	92,092	184,660	368,200	368,200
O&M on Plant	4,396	14,160	32,871	13,216	32,158	58,954	112,084	116,830
Ash Disposal	745	2,400	8,070	2,240	7,980	16,100	32,200	32,200
O&M on Transmission	700	1,800	3,600	8,000	15,000	24,000	43,000	48,000
Total 1970 Production Cost	17,635	52,536	152,104	58,915	165,903	315,753	612,800	622,546
Total 1975 Production Cost	22,508	67,052	194,130	75,193	211,742	402,996	782,117	794,555
Energy Delivered to System (GWH)	7,440	23,730	79,300	21,730	75,920	151,360	301,300	298,100
Production 1970 mills/kwh	2.37	2.21	1.92	2.71	2.19	2.09	2.03	2.09
Production 1975 mills/kwh	3.03	2.83	2.45	3.46	2.79	2.66	2.60	2.67

TRANSMISSION RESPONSIBILITY

For large development in the coal field where the more distant users must provide transmission to their receiving points, the likelihood is that local alternatives may tend to be more attractive for these users; yet, without these added power requirements, the project in its large size probably cannot be justified. Therefore, a method of assigning transmission responsibility has been developed which is referred to as a modified kw mile method. In this approach, three-fourths of the ownership and operating responsibility for the entire transmission system is shared by all users in proportion to their straight-line distance from the generating complex times their kw ownership in the generating complex and one-fourth of the transmission system is shared in by all users in proportion to their kw ownership in the generating complex.

Alternative methods for sharing costs are also possible and may prove more feasible than the modified kw-mile scheme chosen for presentation in this report. Essentially, all large power users in the eastern North Central Power Study area are situated in the eastern portion of that area; therefore, in order to economically justify a large power supply complex on the study area coal fields, it will be necessary to make the program as attractive as possible to these larger utilities. This can be done to some extent by allocating the cost of participation in the transmission programs on an average rate basis. Under this concept pro rata costs of transmission would be shared equally, kilowatt for kilowatt, whether the participant is within 100 or 600 miles of the plant site.

METHOD OF ANALYSIS BY THE PARTIES

Application of the kw-mile approach requires that a model first be developed which quantitatively describes the weighted usage of the transmission system which then is used as the denominator in each party's assessment of the attractiveness of this development. Because the power is not continuously extractable from the line, but is available only at discrete points, this calculation must be based upon the substation delivery points from which the parties will receive power. A diagram depicting the projected power flow for the 4,000 mw plan together with the estimated transmission mileages involved is shown in Figure III E-1. The approximate air mileages, as differentiated from transmission mileages, between the Gillette-Colstrip area and the various delivery points are shown on Table III E-8. The assumed deliveries at each point for the 4,000-mw plan and the 50,000-mw plan are also shown on Table III E-8. From this table, the weighted kw-mile figure is developed and from this each party making an ownership participation analysis can determine the substation from which its power will be received and the appropriate kw-mile factor. An example of this application follows.

Oahe is 260 miles from Gillette with an assumed delivery of 90 mw. Therefore, the factor for Oahe is 23,400 mw-miles. Total is 1,843,550 mw-miles resulting in the Oahe delivery point share of the total transmission are:

$$.25 \times \frac{90 \text{ mw (Oahe)}}{2{,}910 \text{ mw (Total)}} +$$

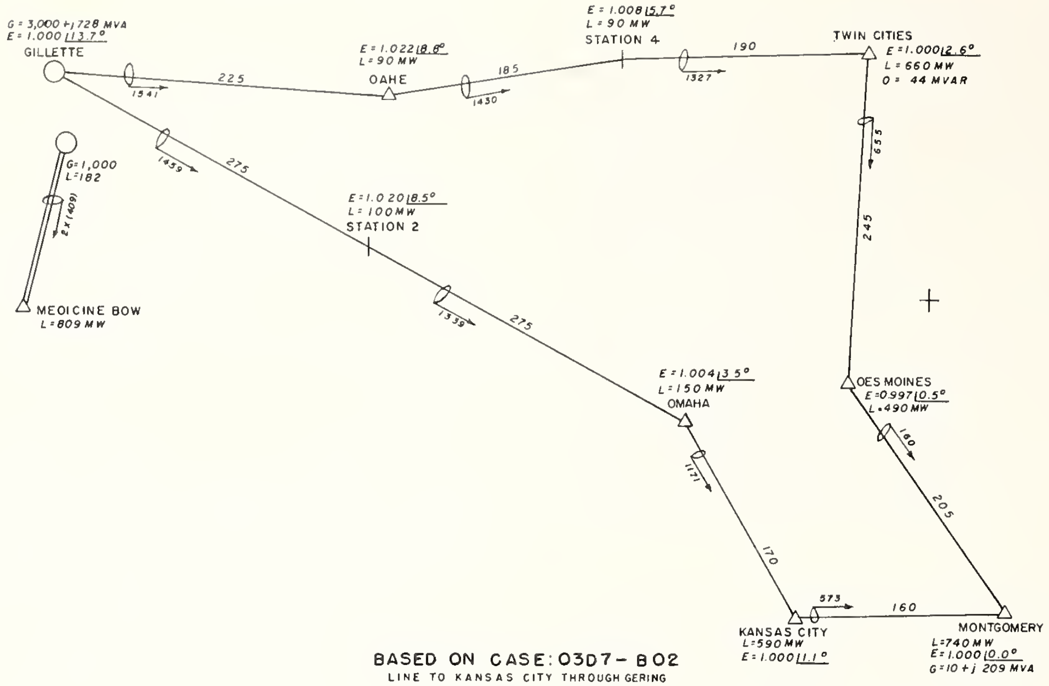
$$.75 \times \frac{23{,}400 \text{ mw-miles (Oahe)}}{1{,}843{,}550 \text{ mw-miles (Total)}} = .01725$$

Therefore, a utility receiving 90 mw at Oahe would be responsible for about 1.7 percent of the total transmission system investment and transmission operating costs. The percentage share for each delivery point using the formula and the 4,000-mw and 50,000-mw plans are shown on Table III E-9.

It must be appreciated that proposed overall participation in the generating complex may vary substantially from the model shown. It is anticipated then that the responses to this report will be used in an iterative process to determine a new model and that this new model then will be used to elicit further response. Additionally, the pattern of responses may ultimately require a different ratio than the one-fourth/three-fourths weighting to make this development feasible. Because of this expectation, the 4,000-mw and 50,000-mw developments only are being offered for evaluation by the parties. However, to provide a basis for knowing the effect of further development, the curve in Figure III E-2 has been derived which shows the relationship between the various levels of generation and the total transmission investment per kw. This curve shows a continuing reduction in this factor. It follows then that the responsibility for participating investment in transmission will decrease a like percentage, which can be used in the overall analysis by the parties.

Figures III E-3 and III E-4 present the basic curves by which each party may determine the preliminary assessment of the cost per kwhr for his participation in the 4,000-mw development. Figures III E-5 and III E-6 present the curves for the 50,000-mw development. In each, the family of curves for varying levelized annual requirements includes that for the composite annual revenue requirement of 11.3 percent. This composite annual revenue requirement rate has been developed as shown on Table III E-10, assuming 50 percent of the project would be sponsored by investor-owned utilities, 35 percent by cooperatives or public power districts and 15 percent by municipals.

The procedure then is for a system to determine its location on the distance-axis of Figures III E-3 through E-6. By properly interpolating between the percent revenue requirement curves, its total cost per kwhr is found. As an example, in Figure III E-3, the Twin Cities are 575 miles from the generating complex. With annual revenue requirements of 10 percent, the total energy cost is 9.25 mills/kwh. With a rate of return requirement of 15 percent, the total energy cost is 12.7 mills/kwh.



BASED ON CASE: 03D7-802
LINE TO KANSAS CITY THROUGH GERING
REROUTED THROUGH OMAHA
Figure IIIE—1

Table III E-8

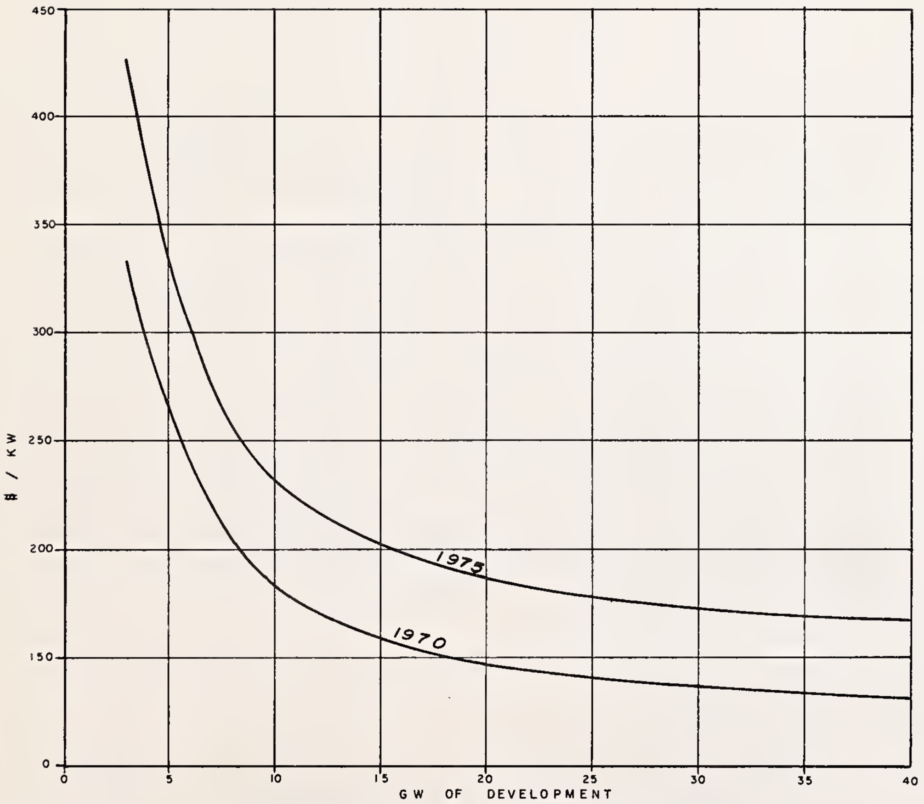
DELIVERY POINTS ASSUMED IN STUDY

Delivery Point	Air Mileage from Gillette (miles)	Power Delivered to this Point (mw) 3,000 mw Development	40,000 mw Development
Eastern			
Oahe	260	90	1,200
Station No. 4	420	90	0
Twin Cities	575	660	8,560
Des Moines	625	490	6,340
St. Louis	815	740	9,136
Kansas City	650	590	7,580
Omaha	550	150	1,920
Station No. 2	275	100	0
Gering	200	0	1,360
Utica Junction	410	0	1,200
Sum of mw-miles		1,843,550	23,389,340
TOTAL		2,910	37,296
		1,000 mw Development	10,000 mw Development
Western			
Gillette	0	182	1,822
Medicine Bow	175	809	7,995
Sum of mw-miles		141,575	1,399,125
TOTAL		991	9,817

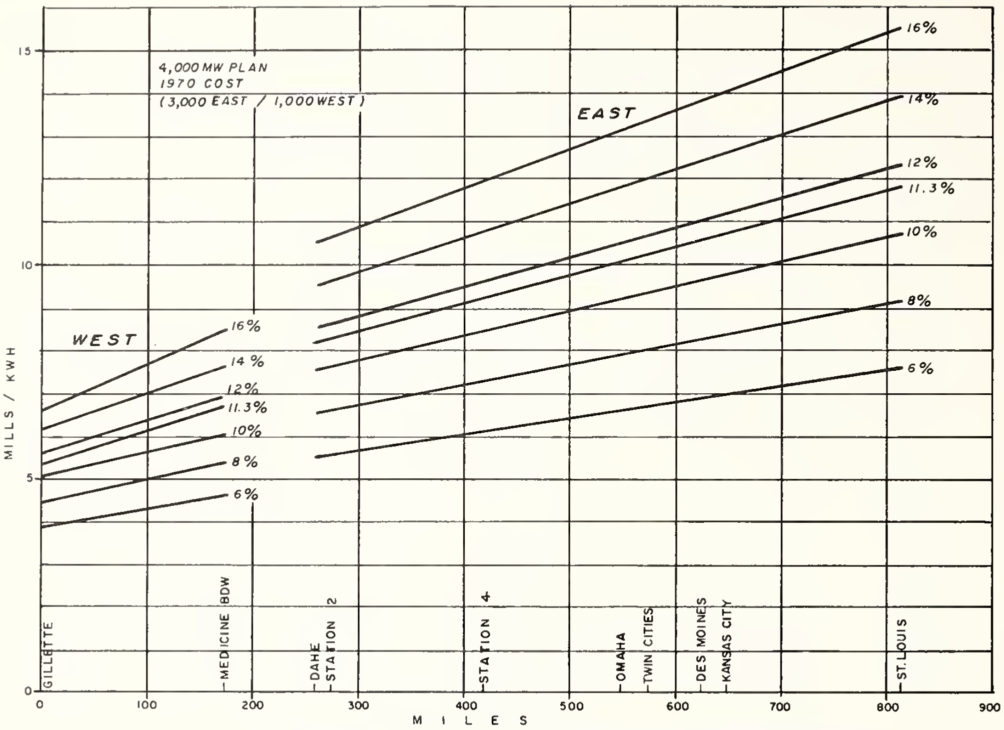
Table III E-9

APPROXIMATE SHARE OF TRANSMISSION

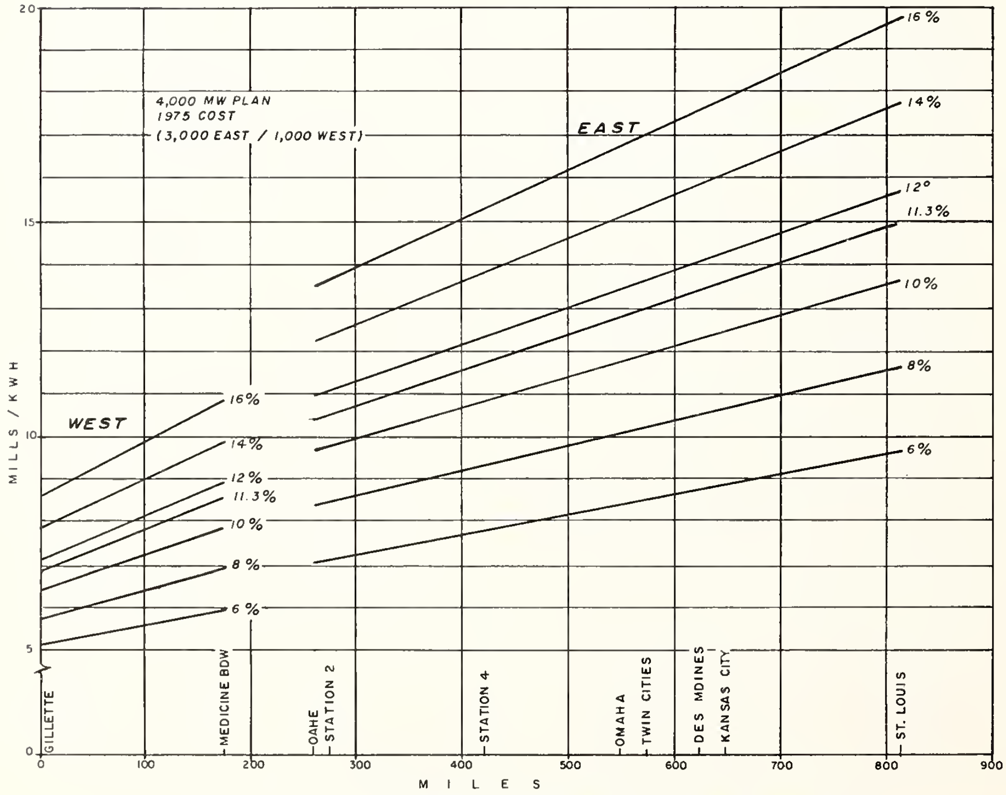
Delivery Point	% Responsibility 3,000 mw Plan	 40,000 mw Plan
Eastern		
Oahe	1.725	1.809
Station No. 4	2.311	0
Twin Cities	21.109	21.519
Des Moines	16.669	16.956
St. Louis	30.893	30.000
Kansas City	20.670	20.879
Omaha	4.645	4.673
Station No. 2	1.978	0
Gering	0	1.784
Utica Junction	0	2.382
TOTAL	100.000	100.000
	1,000 mw Plan	10,000 mw Plan
Western		
Gillette	4.640	4.640
Medicine Bow	93.360	93.360



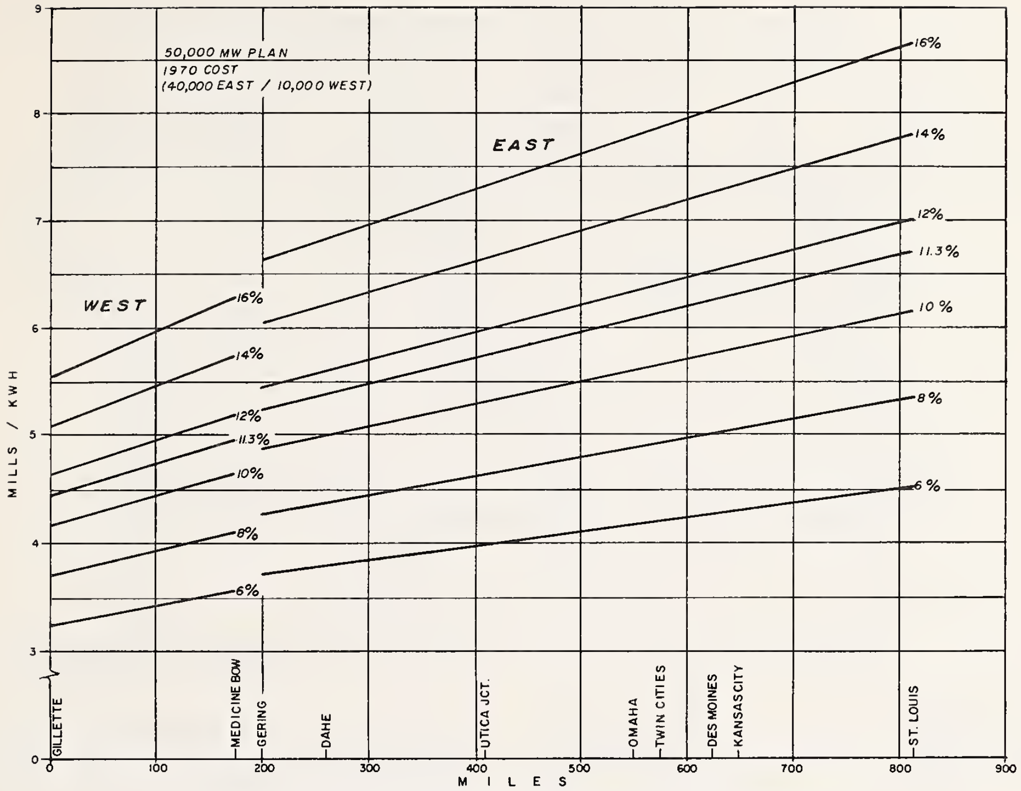
INVESTMENT COST OF TRANSMISSION SYSTEM
Figure III E-2



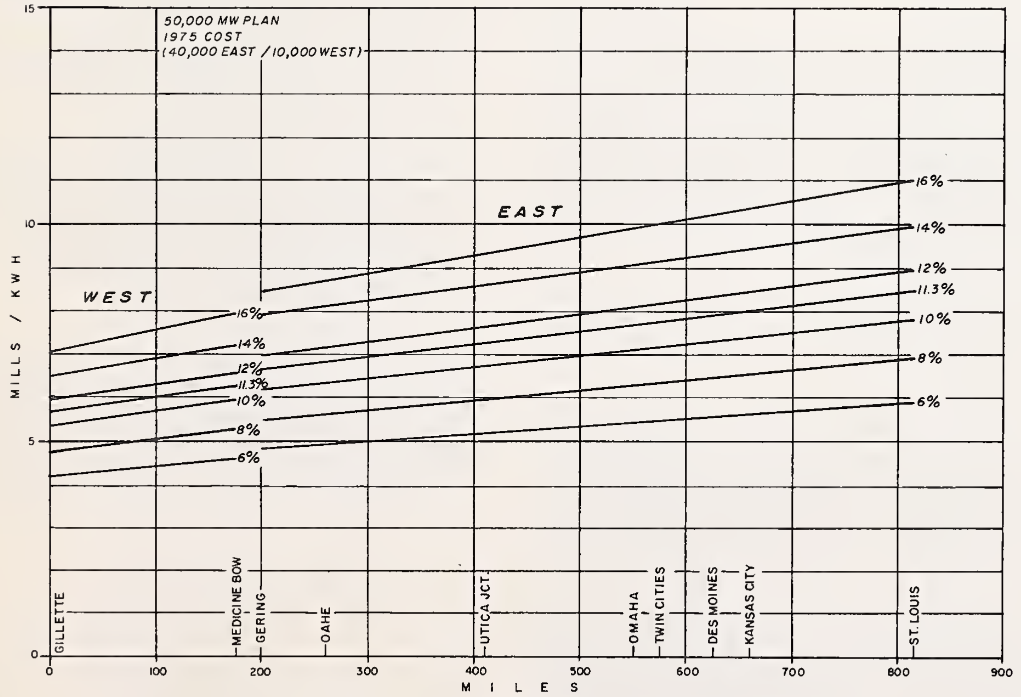
TOTAL PARTICIPATION COSTS FOR VARIOUS FIXED CHARGE RATES
Figure III E-3



TOTAL PARTICIPATION COSTS FOR VARIOUS FIXED CHARGE RATES
Figure III E-4



TOTAL PARTICIPATION COSTS FOR VARIOUS FIXED CHARGE RATES
Figure III E-5



TOTAL PARTICIPATION COSTS FOR VARIOUS FIXED CHARGE RATES
Figure III E-6

Table III E-10

LEVELIZED ANNUAL REVENUE REQUIREMENTS FOR VARIOUS TYPES OF UTILITIES

	%				
	Federal	Municipal	Cooperative	Investor Owned	Composite
Type of Financing & Proportion					
Bond	100	100	100	50	
Preferred Stock				15	
Equity				35	
Component of Revenue Requirement and Approximate % of Investment					
Bond	5.375	6.50	6.75	8.00	
Preferred	---	---	---	8.00	
Equity	---	---	---	12.00	
Total Return	5.375	6.50	6.75	9.40	8.04
Income Tax (Federal & State)	---	---	---	3.13	1.57
Depreciation	.990	.78	.74	.42	.59
Insurance	.100	.10	.10	.10	.10
Total Revenue Requirement					10.30
Property Tax*					1.0
Total					11.30

* Based on expectations considering areas of construction and the large size of development.

III F LEGAL

CONCLUSION

The Committee knows of no overriding obstacles to development of large generating complexes and a transmission system in the North Central region.

HISTORY

Through the Study Manager, the Steering Committee and Coordinating Committee issued instructions that the Legal Committee do no further work on Phase One of the Study with the following two exceptions: (1) Consider and reply to specific questions, and (2) write a short section for the report to the effect that no major obstacles can be foreseen to implementation of the development.

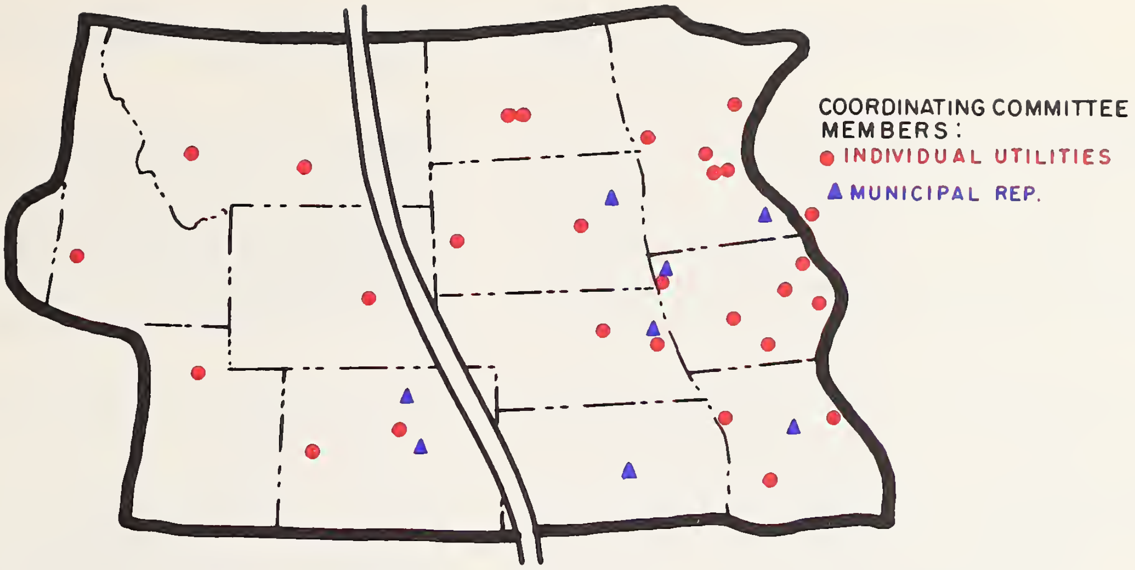
No specific questions were submitted.

RATIONALE

Until a particular development is actually proposed, no specific legal research or memoranda can be developed. In this connection, there is need for answers to a number of questions such as the following:

1. The size of the proposed generating facilities should be determined. If the plant is so large that a large number of participants will be necessary, that will require consideration of different schemes of participation than if the plant is much smaller and only a few organizations participate.
2. The number and type of participants must be known before contract can be worked out.
3. The location of the proposed plant will determine which local laws are involved.
4. The exact location of the proposed plant needs to be known before contracts can be developed to be used with the owners of resources involved.
5. The number and type of participants will determine what financing plans to be used.
6. Until it is known what transmission lines will be built, the areas they will transverse and the purposes they will serve, it is not really feasible to work out legal arrangements as to construction, operation and interconnection.

In spite of the inability to develop specific contract forms until the answers to the above questions are known, the Committee can report that it knows no overriding legal obstacles to development of large generating complexes and a transmission system in the North Central region.



PARTICIPANTS

IV. PARTICIPANTS

NCPS participants are listed below according to their study-organizational segment. The seven Steering Committee members were also members of the Coordinating Committee.

The entire geographic area of the Study was represented and membership came from all segments of the power industry. The Coordinating Committee was composed of management personnel from 19 investor-owned utilities, six cooperatives, two public power districts, one Federal agency and eight representatives from the municipal sector.

COORDINATING COMMITTEE

Stanley M. Swanson, Chairman	Iowa Public Service Company
Neil L. Adams	Associated Electric Cooperative, Inc.
H. E. Aldrich	Bureau of Reclamation
Robert Asheim	Black Hills Power and Light Company
George Beard	Pacific Power and Light Company
Harold H. Brown	Iowa Electric Light and Power Company
D. L. Bryner	Utah Power and Light Company
John J. Bugas	Colorado-Ute Electric Association, Inc.
Stan Case	Municipals
Fred D. Diehl	Municipals
Darrell Frankson	Municipals
Ed C. Glass	Northern States Power Company
James L. Grahl	Basin Electric Power Cooperative
R.O.M. Grutle	Otter Tail Power Company
Glenn Hall	Idaho Power Company
David Kopecky	United Power Association
Milton Launer	Municipals
Ted V. Lennick	Cooperative Power Association
Frank Linder	Dairyland Power Cooperative
James H. Lundsted	Municipals
James R. Lyon	Iowa Power and Light Company
G. J. Lyshoj	Interstate Power Company
Robert O. Marritz	Municipals
Richard B. Miller	Iowa-Illinois Gas and Electric Company
W. C. McCarthy	Kansas City Power and Light Company
H. N. McCoy	Union Electric Company
Harold O. Moe	Municipals
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